Preliminary positions

Framework and approach paper

Aurora Energy Pty Ltd

Regulatory control period commencing 1 July 2012

June 2010

AUSTRALIAN ENERGY REGULATOR

Inquiries about this document should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: (03) 9290 1444
Fax: (03) 9290 1457
Email: AERInquiry@aer.gov.au

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Request for submissions

Issues regarding the AER's preliminary positions can be addressed in written submissions to the AER by **9 August 2010**.

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

Alternatively, submissions can be mailed to:

Mr Chris Pattas
General Manager
Network Regulation South
Australian Energy Regulator
GPO Box 520
Melbourne VIC 3000

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

- clearly identify the information that is the subject of the confidentiality claim, and
- provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be placed on the AER's website at http://www.aer.gov.au. For further information regarding the AER's use and disclosure of information provided to it, see the *ACCC/AER Information Policy*, October 2008 also available on the AER's website.

Enquiries about this paper, or about lodging submissions, should be directed to the Network Regulation South branch of the AER on (03) 9290 1436.

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 preliminary position on classification, form of control and approach to 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]

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

The AER's preliminary position is to classify:

- 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) and special distribution services currently provided by Aurora as alternative control services, with these services being grouped in the following way:
  - metering services
  - public lighting services
  - fee based 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
- non-standard (quoted) services

Customer contributions for connections will remain unregulated. However, the Ministerial Council on Energy (MCE) has recently endorsed a set of policy provisions that will under that will underpin the legislation to give effect to the National Energy Customer Framework (NECF).[2] The AER understands that this will include an accessible framework for customers to arrange new connections to connect to electricity networks.

Control mechanisms

The AER's preliminary position 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 preliminary position is to apply a price cap form of control to the above services for which the AER's preliminary position is to classify as alternative control services. In particular, the AER's preliminary position is to:

- retain the current control mechanism for metering services, and for the reference set of special services

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2 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 control mechanism for 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.[3] In the event of a dispute, the AER will arbitrate in accordance with the same criteria and with regard to the approved framework.[4]

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.[5] 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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[3] NER, cl. 6.7.2.

[4] NER, cl. 6.22.2(c).

[5] 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 preliminary position 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 AER notes that the STPIS scheme states that the guaranteed service level (GSL) component of the STPIS will not apply where an existing jurisdictional GSL scheme applies. As a Tasmanian specific GSL scheme currently applies under the Tasmanian Electricity Code (TEC), the AER's preliminary position is to not apply the GSL component of the STPIS. The AER will apply the GSL component of the STPIS if the existing Tasmanian GSL scheme is repealed. OTTER has not indicated that it intends to repeal the GSL scheme that applies to Aurora.

Application of demand management incentive scheme

This paper sets out the AER's preliminary position on the application of a proposed demand management incentive scheme (DMIS) to Aurora for the forthcoming regulatory control period. In its framework and approach paper, the AER will take into account submissions on both this paper and the proposed DMIS in setting out its likely approach to the application of the final DMIS for Aurora.

The distribution consultation procedures 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. Within 80 business days of publishing the proposed DMIS, the AER must publish its final decision and DMIS. The AER has commenced this process by releasing consultation documentation on its proposed DMIS for Aurora concurrently with the release of this preliminary positions paper. The AER's proposed DMIS for Aurora and its explanatory statement are available on the AER's website at http://www.aer.gov.au.

The AER proposes to apply a DMIS in the form of a demand management innovation allowance (DMIA) to Aurora. The AER's preliminary position 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 preliminary position 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.[6]

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.[7]

Consultation process

The framework and approach paper must be prepared in consultation with Aurora and with other interested stakeholders.

The AER must commence consultation on its framework and approach paper for Aurora on 30 June 2010, and must complete and publish the framework and approach paper by 30 November 2010. The AER seeks submissions from interested parties by 9 August 2010.

The process that will be adopted by the AER is set out below:

Table 1 Process for preparation of and consultation on framework and approach paper

Publication of preliminary positions paper	**25 June 2010**
Stakeholder forum	*Mid August 2010**
Submissions on preliminary positions and proposed DMIS close	9 August 2010
Publication of final framework and approach paper	**30 November 2010**

* Subject to sufficient interest from stakeholders.

6 AER, *Electricity distribution network service providers—Cost allocation guidelines*, June 2008.

7 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).[8] 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. This step in the process commences on 30 June 2010 with the publication of this preliminary positions paper on the framework and approach and is completed with the publication of the final framework and approach.

1.1 Nature of 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[9]
- 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
  3. the application of an efficiency benefit sharing scheme (EBSS) or schemes

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

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[10]

- providing a statement of the AER's likely approach to cost allocation based on the guidelines currently in force.[11]
- 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.[12] If a DNSP owns, controls or operates dual functions 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.[13] 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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10 NER, cl. 6.8.1(b).

11 NER, cl. 6.15.4(b).

12 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).

13 NER, cl. 6.25.

Table 1.1 Procedures for making a distribution determination

1	**AER's framework and approach paper**	
	AER publishes preliminary positions paper for its framework and approach paper for Aurora	25 June 2010
	AER to publish framework and approach paper for Aurora	30 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 preliminary positions 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 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.[14]

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.

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

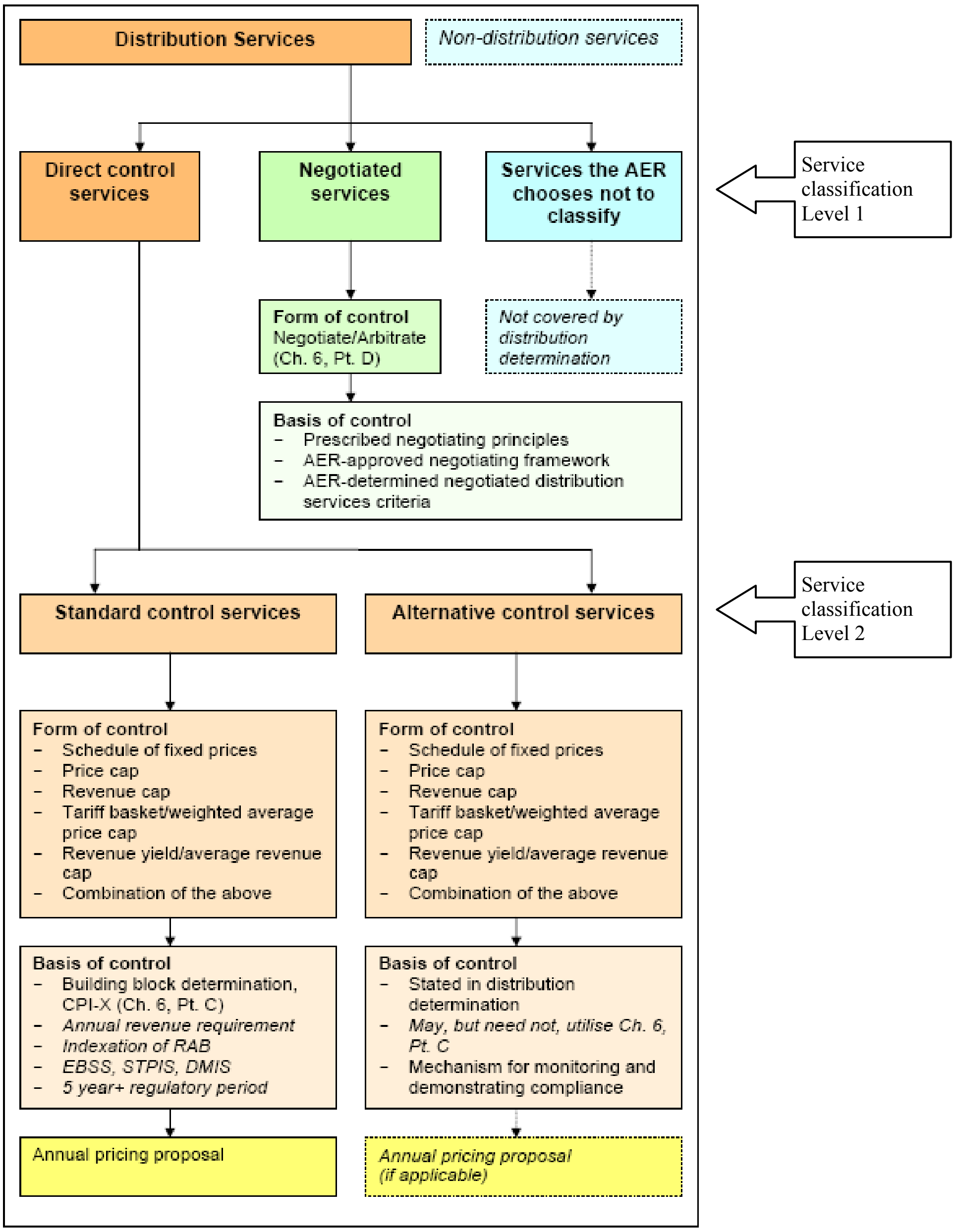
2. where the AER classifies a distribution service as a direct control service it must further classify it as either:

   i. a standard control service, or

   ii. an alternative control service.[15]

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.

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

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.[16] In addition, non-distribution services cannot be regulated under the NER.

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.[17] In the event of a dispute, the AER will arbitrate in accordance with these criteria and with regard to the approved framework.[18]

The distribution determination must impose a control on the price of, and/or revenue derived from, direct control services.[19] 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.[20]

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.[21] The AER's distribution determination must include a decision on how compliance with the relevant control mechanism is to be demonstrated.[22]

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.[23] The distribution determination must state the basis for the control mechanism applied to any alternative control services,[24] and must include a decision on how compliance with the control mechanism is to be demonstrated.[25]

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16 NER, cl. 6.2.1(a).
17 NER, cl. 6.7.2.
18 NER, cl. 6.22.2(c).
19 NER, cl. 6.2.5(a).
20 NER, cl. 6.2.5(b).
21 NER, cl. 6.2.5(a).
22 NER, cl. 6.12.1(13).
23 NER, cl. 6.2.6(c).
24 NER, cl. 6.2.6(b).
25 NER, cl. 6.12.1(13).

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.[26]

The incentive schemes developed by the AER under chapter 6 of the NER apply only to standard control services.[27]

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 preliminary position on the 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.

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26 NER, cl. 6.18.2(a).
27 NER, cll. 6.5.8, 6.6.2 and 6.6.3.

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,[28]
- 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.[29]

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.[30] 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.[31]

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28 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.

29 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.

30 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.

31 NER, cl. 6.2.1(c).

2.2 Requirements of the NEL and NER

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.[32] 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.[33] 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.[34] If the AER decides against classifying a distribution service, the service is not regulated under the NER.[35]

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.[36]

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.[37] Similarly, direct control services may be grouped as standard control services or alternative control services.[38] 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.[39] 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.[40]

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.

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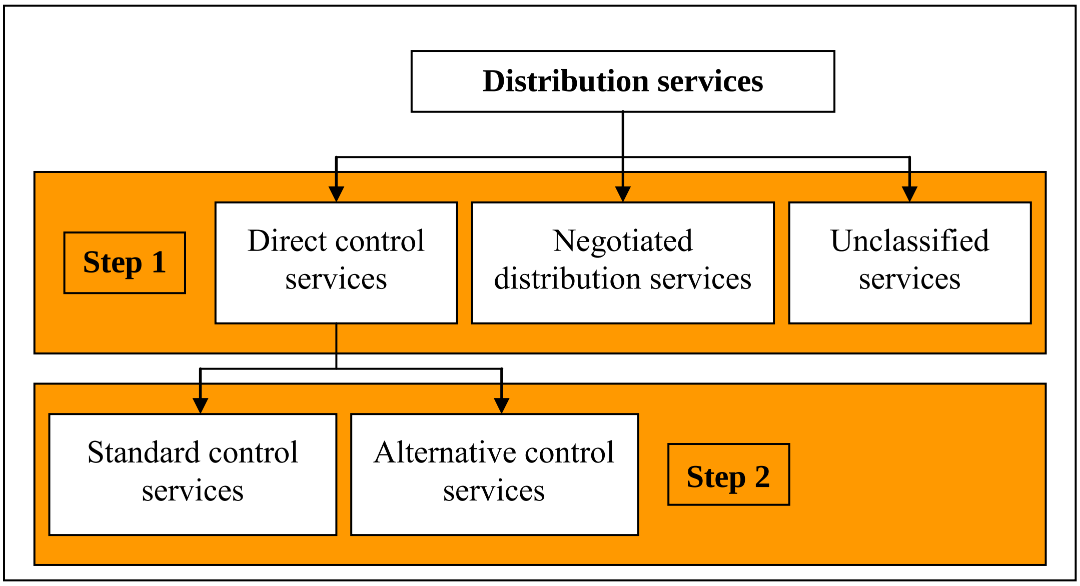
32 NER, cl. 6.12.1(1).
33 NER, cl. 6.2.3.
34 NER, cl. 6.8.1(b)(1).
35 Refer note at NER, cl. 6.2.1.
36 NER, cl. 6.12.3(b).
37 NER, cl. 6.2.1(b).
38 NER, cl. 6.2.2(b).
39 NER, cll. 6.2.1(e) and 6.2.2(e).
40 NER, cll. 6.2.1(d) and 6.2.2(d).

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 in section 2F of the NEL:

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

- 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

- 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

- 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

- 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

- 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

- 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.[41]

(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.[42]

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.[43]

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).

41 NEL, s. 2F.
42 NER, cl. 6.2.1(c).
43 NER, cl. 6.2.2(c).

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. Among other things, the ESI Act establishes OTTER's role as the economic regulator and provides OTTER with the role of administering the TEC.

OTTER's obligations under the 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.[44]

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

2.3.1.1 Distribution network services

OTTER defined distribution network services as follows:[45]

> **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:[46]

> **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.[47] They also do not include the special meters used to provide Aurora’s ‘pay as you go’ (PAYG) service which are owned by Aurora’s retail division. Metering services are currently regulated under a price cap.

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44 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).

45 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).

46 ibid. p. i, p. 16.

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

2.3.1.3 Special services

In its 2007 statement of reasons, OTTER defined special services as:[48]

> **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.[49] Tables 2.4 and 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.[50]

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

49 OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania—Supplementary Final Report and Statement of Reasons on Maximum Prices for Special Services Provided by Aurora Energy*, June 2008, pp. 12–17 (OTTER, *Maximum Prices for Special Services*, June 2008).

50 ibid., p. 19.

The following special services are currently not regulated and the AER understands they 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
- 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 Issues and AER's considerations

2.4.1 Distribution services

Under the NER, the AER must make a positive decision to classify a service as a direct control or negotiated distribution service, 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 applying previously, unless another classification is clearly more appropriate.

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'.[51] 'Distribution system' is defined in the NER as a 'distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system. Connection assets on their own do not constitute a distribution system'.[52]

Chapter 10 of the NER further expands 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, quoted services and unregulated services are distribution services.

2.4.2 Considerations relevant to classification of services

Under the NER, the AER must make a positive decision to classify services as direct control or negotiated distribution services (or decide against classifying a distribution service). If the AER decides to classify any distribution services as direct control services, it must further divide these services into standard control or alternative control services. This classification process 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 applying previously or, where there has been no classification, that the classification be consistent with the previous applicable regulatory approach, unless another classification is clearly more appropriate.[53]

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.[54] 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).[55]

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.

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51 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.
52 NER, chapter 10.
53 NER, cl 6.2.1(d).
54 NER, cll. 6.2.1(e) and 6.2.2(e).
55 NER, cll. 6.2.1(d) and 6.2.2(d).

The AER's preliminary position is that there are some services where a different classification is clearly more appropriate.

The AER acknowledges the need to classify services in such a way as to allow flexibility for DNSPs to alter the exact specification (but not the nature) of a service during the regulatory control period. At the same time, the AER needs to provide certainty as to how specific services, particularly new services that may arise during a regulatory control period, are classified. This balance can be achieved by grouping services for the purpose of classification as provided for by the NER.[56]

The AER considers that this approach to service classification has the advantage of classifying a class of activities, rather than the specific activities performed as part of the service, allowing the specific definition or magnitude of services to change whilst maintaining the desired classification. Such broad classifications may be combined with a list of specific services that are included (but not limited to) that classification grouping.

2.4.3 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 a different classification is clearly more appropriate.

Grouping of services

Clause 6.2.1(b) of the NER provides for the AER to group distribution services together for the purposes of classification and, if it does so, a single classification made for the group applies to each service comprised in the group as if it had been separately classified. Having regard to the previous grouping of services and the grouping of services in other jurisdictions, the AER considers that it is appropriate to group the electricity distribution services provided by Aurora in the following way:

- network services
- metering services
- public lighting
- connection services
- fee based services
- non-standard services.

2.4.3.1 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

[56] NER, cll. 6.2.1(b) and 6.2.2(b).

the shared network. Network services are delivered through the provision and operation of apparatus, equipment, plant and / or buildings (excluding connection 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'.[57]

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.[58]

The AER understands that network services are characteristically provided by Aurora on a 'standard' basis, with the 'above standard' supply of these services generally dealt with on a fixed fee or quoted basis. The AER considers an above standard network supply as being the provision of a higher standard of reliability or quality of supply, which would be provided by a DNSP by providing assets which enable greater reliability or quality of supply at a customer's premises. The AER further understands these assets would be supplied as a:

- fee based service, if the cost of works can be gauged in advance and therefore a single price can be set
- quoted service, if the price can not be set in advance, and an assessment of the specific request has to be made.

The AER understands that above standard network services are currently unregulated.

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

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

Issues and AER considerations

Standard network services

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 clause 18 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 to entry for the purposes of section 2F(a) of the NEL. This is because Aurora, as the only holder of an electricity distribution licence in Tasmania, is the only party that can provide these network services within the areas prescribed in its licence.

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 generators 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—this is also the case in the other NEM jurisdictions.

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 are no other relevant factors that change the AER's proposed classification.

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

Above standard network services

Aurora has advised the AER that characteristically, network services are provided on a standard basis, and any above standard network services are generally dealt with on either a fixed fee or quoted basis, depending on the nature and scope of the customer's request.[59] The AER notes that the specific services that Aurora provides on a fixed fee basis are listed above (section 2.3.1) and are discussed in more detail in section 2.4.3.4. Services provided on a quoted basis—non-standard services—are discussed below in section 2.4.3.6.

[59] Aurora, *Information paper for AER: services, classifications and control mechanisms—Framework and approach process*, May 2010, p. 14. (Aurora, *Information paper*, May 2010)

Aurora has also advised the AER that above standard network supply refers to the provision of a higher standard of reliability or quality of supply, which would be provided by Aurora by providing assets that enable greater reliability or quality of supply at a customer's premises.[60] The AER understands that these services deliver specific benefits to the customer that requested the service (and not to the network more broadly), and are generally subject to negotiation between Aurora and the customer. The AER also understands that the cost associated with these services can be clearly identified and attributed to the specific customer request. The AER therefore considers that there is merit in discussing above standard network services in the context of fee based services (section 2.4.3.4) and non-standard services (section 2.4.3.6).

The AER seeks stakeholder views as to its proposed classification of network services, including above standard network services.

In particular, the AER seeks stakeholder views on the treatment of above standard network services as fee based or non-standard services, or whether another classification is more appropriate.

AER's preliminary position

The AER's preliminary position is that Aurora's standard network services should be classified in a manner 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's preliminary position is that network services should be classified as direct control services and, in turn, as standard control services. This is supported by the AER's assessment against the factors in clause 6.2.1 and 6.2.2 of the NER.

With respect to above standard network services, see the discussion relating to fee based and non-standard services in sections 2.4.3.4 and 2.4.3.6 respectively.

2.4.3.2 Metering

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 (i.e. excluding the provision of metering to a standard in excess of that required for billing of services—see section 2.4.3.6 for above standard metering services).

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:

[60] ibid.

(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.

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.[61] In 2007, however, OTTER elected to separately declare type 5, 6 and 7 (but not type 1 to 4) metering services.[62] OTTER expected that type 1 to 4 meters would be contestable in future (which they are) and hence were not part of the declaration.

OTTER's 2007 declaration also makes it clear that 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.[63] The AER notes that there was no discussion of electronic metering in OTTER's 2007 declaration.

Electronic metering services

The AER notes that Aurora's approach to electronic metering services is consistent with Aurora's 2007 Electricity Pricing Investigation—final report, which stated that its 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.

The AER considers that electronic metering services for type 5, 6 and 7 meters (excluding PAYG metering services), will be direct control services for amongst other reasons, the economies of scale and scope available to Aurora, which make it unlikely that smart metering services will be able to be competitively provided by an alternative service provider.

PAYG metering services

The AER understands that Aurora's retail PAYG tariff represents a large part of the retail market in Tasmania. Specifically, the AER understands that Aurora currently has approximately 40 000 PAYG customers. The AER further notes that of these 40 000 PAYG customers, approximately 500 have standard electronic meters (provided by Aurora), and a Payguard unit provided by Aurora Retail to handle the PAYG functionality.[64]

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

62 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.

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

64 Aurora, *Information paper*, May 2010, p. 9.

Aurora's PAYG meters were excluded from the definition of metering services in OTTER's 2007 declaration decision and are not regulated. OTTER considered that the customer always had the option to revert back to the regulated alternative, but was also concerned that subjecting these meters to regulation would 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.*[65]

The AER notes that the PAYG service is provided by Aurora Retail and is a time of use service. That is, the average cost for PAYG depends on how much power is consumed and at what time of the day and year it is consumed. The AER also notes that PAYG prices are, on average, higher than for tariff customers, although OTTER has found that this difference is principally due to:

- average increases in network costs
- the costs of technology required to support the prepayment meters
- the costs of maintaining a point of sale agent network.[66]

With respect to recent and future customers requiring PAYG metering services, the AER notes that they have been and will continue to be provided with electronic meters complemented with a Payguard unit that allows the PAYG service to be provided. The AER further notes that the Payguard unit will be provided and owned by Aurora retail.

The AER seeks stakeholder views on its understanding of the type 5, 6 and 7 metering services as well the PAYG metering services, including the use of electronic metering.

Above standard metering services

With respect to above standard metering services for type 5, 6 and 7 meters, the AER understands that these services are generally dealt with as fee based (section 2.4.3.4) or non-standard services (section 2.4.3.6)—the nature and scope of the customer's request determining what type of service is more suitable. The AER notes, however, that the specific services that Aurora provides on a fixed fee basis are discussed in more detail in section 2.4.3.4.

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

66 OTTER, *Review of Aurora Energy Pty Ltd's Aurora Pay As You Go*, Final report, November 2009, p. xviii.

The AER understands that these above standard metering services deliver specific benefits to the customer that requested them, do not generate any network-wide benefits and the cost associated with these services can be clearly identified and attributed to the specific customer request. The AER therefore considers that there is merit in discussing above standard metering services in the context of fee based services and non-standard services in sections 2.4.3.4 and 2.4.3.6 respectively.

The AER seeks stakeholder views on the appropriateness of referring above standard metering services to fee based and non-standard services.

Issues and AER considerations

Standard type 5, 6 and 7 metering services

The AER understands that the metering services that OTTER regulates under chapter 6 of the NER are all metering services provided to customers associated with type 5 (manually read interval meters), type 6 (accumulation meters) and type 7 (unmetered supplies), excluding integrated prepayment meters used by Aurora in relation to providing PAYG metering services.

Due to the contestable nature of type 1 to 4 meters, the AER has decided not to classify meter provision services and metering data provision services for customers that are served by type 1 to 4 meters.

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[67] for all type 5, 6 and 7 metering installations, which would include PAYG meters.

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 metering services for type 5, 6 and type 7 meters. 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 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 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 all type 5, 6 and 7 metering services, except PAYG 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.

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[67] 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.

Having regard to the requirements of clause 6.2.1 of the NER, the AER considers that all type 5, 6 and 7 metering services, excluding PAYG metering 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) to determine whether it should be classified as a standard or alternative control service.

Type 5, 6 and 7 metering services (excluding PAYG 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 are no other relevant factors that change the AER's proposed classification.

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

PAYG metering services

The AER notes that to a large extent, PAYG metering services have the characteristics of a retail service. This is particularly the case given that the PAYG service for customers with new (distributor owned) electronic meters is enabled using a Payguard unit provided by Aurora Retail (or potentially another retailer in the event retail contestability is expanded further in the future) to handle the PAYG functionality. In addition, the AER understands that currently, the majority of PAYG customers have a meter that is provided by Aurora Retail.[68]

As outlined above, the AER notes that OTTER determined that it was appropriate to exclude prepayment meters from its 2007 declaration. Specifically, OTTER considered that only the safety net tariffs should be regulated by way of maximum prices and that PAYG meters were additional to standard accumulation metering services. That is, customers were free to choose to revert back to standard accumulation meters if this service did not suit their needs in terms of service and / or price. In other words, standard accumulation meters and PAYG meters are substitutable. On this basis, OTTER decided not to regulate these meters.[69]

OTTER also considered that to regulate maximum prices, by including PAYG meters in the suite of regulated meters, would result in partial regulation of PAYG product prices. In addition, it considered that there are likely to be changes in the type of meters used for the PAYG services and regulation of prices may be an impediment to Aurora (or any other potential DNSP), in adopting emerging technology or providing 'new' and / or innovative distribution services to customers.[70]

The AER also notes that clause 6.2.1(d)(2) of the NER requires the AER, where there has been no previous regulation, to determine a classification that is consistent with the previously applicable regulatory approach, unless a different classification is clearly more appropriate. The AER notes OTTER's rationale for not regulating PAYG services—the availability of standard accumulation meters as a direct substitute, combined with some concern over the scope for this to stifle innovation—and also does not consider that PAYG metering services should be classified (and therefore not regulated under the NER).

AER's preliminary position

The AER's preliminary position is 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. This is supported by the AER's analysis above.

On this basis, the AER considers that:

- metering services, excluding PAYG metering and above standard 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.

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68 Aurora, *Information paper*, May 2010, p. 9.
69 OTTER, *Final report*, Sep 2007, p. 262.
70 ibid.

The AER seeks comment on these proposed classifications. Specifically, the AER welcomes comments on whether it is appropriate to not regulate PAYG metering services.

2.4.3.3 Public lighting services[71]

Aurora operates and maintains the public lighting system throughout Tasmania on behalf of the 29 local councils and other government road authorities, including the Department of Infrastructure, Energy and Resources (DIER), the latter of which is responsible for public lighting on state roads and major highways in Tasmania.

Aurora also owns the majority of public lighting luminaries in Tasmania, where approximately 75 per cent of public lighting is supported on Aurora's electricity distribution poles. The remaining 25 per cent are supported by dedicated public lighting poles which in most cases are privately owned (these are not Aurora's assets).[72]

The AER understands that Aurora provides public lighting services on state roads and highways. The AER also understands that in the majority of new housing developments, the provision of new public lighting, such as the design, installation and connection of public lighting assets, is undertaken by Aurora.

Public lighting services are not defined in the NER, however, in previous distribution determinations for other jurisdictions, the AER has classified the following types of public lighting services:

- the operation, maintenance, repair and replacement of public lighting assets
- the alteration and relocation of public lighting assets, and
- the provision of new public lighting.[73]

The AER has been advised by Aurora that in the Tasmanian context, the operation, maintenance, repair and replacement of public lighting assets can be further categorised into the following services:

- the repair, replacement and maintenance of public lighting owned by Aurora, where the streetlight services are provided to third parties

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71 In developing its preliminary positions on the regulation of public lighting in Tasmania, the AER has conducted preliminary market inquiries to inform its understanding of the existing arrangements for the provision of public lighting services by Aurora. The AER sought information from Aurora, Tasmanian local councils including the Local Government Association of Tasmania (LGAT), the Tasmanian Department of Infrastructure, Energy and Resources (DIER), and other potential providers of public lighting services in Tasmania.

72 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 (Aurora, *Prices for Street Lights*, May 2010).

73 AER, *Framework and approach paper for Victorian electricity distribution regulation—CitiPower, Powercor, Jemena, SP AusNet, and United Energy for regulatory control period commencing 1 January 2010 (final)*, May 2009, pp. 25–26.

- 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.[74]

The AER notes that these categories of public lighting services relate to all types of luminaires currently provided by Aurora. The AER intends to classify the categories of public lighting services identified by Aurora above. The AER does not intend to classify public lighting services for luminaires that are provided on a trial basis, such as LED street lighting.

Public lighting assets, including all street lights in Tasmania are connected to Aurora's electricity distribution network. The conveyance of electricity to public lighting assets is not a defined as a public lighting service, but rather falls within the definition of a network service. The AER's preliminary position on the classification of network services is in section 2.4.3.1 above.

Current classification

The AER notes that OTTER's 2007 declaration statement of reasons clarifies that OTTER decided not to declare public lighting services for the 2007–08 to 2011–12 regulatory control period.[75]

While public lighting services have not been previously subject to economic regulation, Aurora has other regulatory obligations in relation to public lighting services under the TEC. In particular, Aurora is obliged under section 8.2.3 of the TEC to repair or replace an item of public lighting within 7 business days of being notified that repair or replacement is necessary. 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.

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74 Aurora, *Information paper*, May 2010, p. 3–4.

75 OTTER, *Statement of Reasons*, Jan 2007.

76 Aurora, Electricity network distribution charter, http://www.auroraenergy.com.au/electricity_network/network/electricity_network_distribution_charter.asp (accessed on 9 June 2010)

Issues and AER considerations

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. The AER understands that Aurora does not have a legislative monopoly over the provision of public lighting services.[77] However, as noted above, 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.

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 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. Therefore, the AER considers that there are significant barriers to entry for the provision of public lighting assets 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 contends that it 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.[78] The AER also notes that Aurora is also the dominant electricity retail services provider in the Tasmanian retail sector. As is the case for network distribution services, it appears to the AER that Aurora would also benefit from the factors of production that relate to its provision of retail services for the provision of public lighting services, such as staff and customer databases.

The AER understands that 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 on assets owned by Aurora. Aurora remains the sole DNSP in Tasmania, and therefore the only party capable of providing distribution services for its public lighting assets. The AER 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.[79]

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77 Aurora, *Information paper*, May 2010, p. 28.
78 ibid..
79 ibid..

With regard to section 2F(g), it does not appear to the AER that consumers of public lighting services would have sufficient information to negotiate on an informed basis with Aurora. Indeed, from its initial inquiries, the AER understands that there are concerns about the lack of transparency regarding the terms on which public lighting services are provided to consumers. Further, Aurora has only very recently provided the AER with a guideline that describes the basis on which it intends to provide public lighting services to consumers.[80]

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 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. Table 2.2 provides the service classifications as approved by the AER for the other jurisdictions in the NEM.

Table 2.2 Classifications of public lighting services in other NEM jurisdictions

State jurisdiction	**Negotiated distribution services**	**Direct control Services - standard control services**	**Direct control services - alternative control Services**
Victoria	New public lighting Alteration and relocation of DNSP public lighting assets		Operation, repair, replacement and maintenance of DNSP public lighting assets
South Australia	Provision of assets, operation and maintenance Operation and maintenance 'Energy only' service		
Queensland			All street lighting services
NSW			All street lighting services
ACT[a]	Nil	Nil	Nil

(a) Public lighting is not provided as a network service to customers, and is paid for by the ACT Government

80 Aurora, *Prices for Street Lights*, May 2010.

As outlined in Table 2.2, public lighting services in most other NEM jurisdictions are regulated as direct (alternative) control services.[81] 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.

As noted previously, clause 6.2.1(d)(2) of the NER requires the AER, where there has been no previous classification (as is the case here), 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 preliminary position is that 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 as direct control services rather than negotiated distribution services as it would appear that charges for public lighting services can bet determined up-front in the price determination stage, and this may be superior to the potential for a series of negotiated outcomes during the regulatory control period.

The AER seeks comment on its preliminary position to classify public lighting services as direct 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) and classify public lighting services as direct control services, and further classify them as alternative control services. This is because the AER considers:

- 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).

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81 AER, *Framework and approach paper for Victorian electricity distribution regulation—CitiPower, Powercor, Jemena, SP AusNet, and United Energy for regulatory control period commencing 1 January 2010 (final)*, May 2009, pp. 25–26; AER, *Framework and approach paper—ETSA Utilities 2010–15 (final),* November 2008, p. 36; AER, *Framework and approach paper—Classification of services and control mechanisms for Energex and Ergon 2010–15,* August 2008.

- 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.[82] 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, 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.

AER's preliminary position

For the reasons outlined above, the AER considers that it is clearly more appropriate to depart from the current unregulated approach to public lighting services in Tasmania. For the reasons discussed above, the AER's preliminary position is therefore to classify public lighting services as direct control services and further classify them as alternative control services.

The AER seeks comment on its preliminary position to classify public lighting services as alternative control services..

2.4.3.4 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[83] 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.[84]

82 Aurora, *Information paper*, May 2010, p. 8.
83 OTTER, *Maximum Prices for Special Services*, June 2008, p. 5.
84 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 2.4.3.5)
- 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.[85]

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 2.4.3.6).[86]

The AER understands that 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.[87]

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[85] The AER understands that 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.

[86] OTTER, *Maximum Prices for Special Services*, June 2008, p. viii.

[87] Aurora, *Information Paper*, May 2010.

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 costs associated with meter installation and service connection are recovered through DUOS charges.[88] Connection services are further discussed (below) in section 2.4.3.5.

The AER understands that 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.[89]

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.[90] 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.[91]

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.

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

The AER understands that all 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.

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88 OTTER, Response to information requested on 24 May 2010, submitted on 24 May 2010.
89 OTTER, *Maximum Prices for Special Services*, June 2008, p. 19.
90 ibid.
91 ibid.

The AER also understands that:

- The network services provided by Aurora (section 2.4.3.1) provide positive externalities in the supply of fee based services, which could limit the prospect of effective competition in the market for fee based services. These network externalities may lead to barriers to entry, either in price or quality of service provided, which in turn may increase the market power of Aurora.

- The fee based services are generally provided to specific customers on an 'as needs basis', which means that they would be unlikely to have substantial negotiating power in determining the price and other terms and conditions on which these services are provided.

The AER considers, as per 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 the reference set of fee based services. Furthermore, 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. 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 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.

- 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 are no other relevant factors that change 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 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. 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.

In relation to clause 6.2.1(c)(2), the AER notes that 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 monopoly power such that customers would benefit from price cap regulation of these services.[92] 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.

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[92] ibid.

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.

For the purposes of this preliminary positions paper, the AER considers that other distribution special services are currently unregulated. However, the AER considers for the reasons discussed above (in relation to clause 6.2.1(c)(2) of the NER), that for the purposes of clause 6.2.1(d) of the NER, other distribution special services 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 (as with the reference set), other distribution special 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, 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 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.[93] 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.[94]

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

- There are no other relevant factors that change the AER's proposed classification.

The AER's preliminary position is that OTTER's treatment of other distribution special services indicates that they should be classified as alternative control services in the forthcoming regulatory control period, having regard to the requirements of clauses 6.1.2 and 6.2.2 of the NER.

The AER seeks interested parties views on whether the classification of other distribution special services as alternative control services is consistent with the previously applicable regulatory approach.

AER's preliminary position

The AER's preliminary position for special services is that:

- The reference set of special services should be classified in a manner 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.

- The special services that fall outside of the reference set of special services—other distribution special services—should also be classified as alternative control services. 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 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 considers 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.

The AER seeks comment on these proposed classifications. Specifically, the AER seeks comment on how it has classified the reference set of special services and other distribution special services.

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

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

2.4.3.5 Connection services

Chapter 10 of the NER 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.

Clause 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 clause 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 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 (2.4.3.4).

> The AER notes that clause 6.6.1 of the TEC requires Aurora to have an OTTER-approved procedure in place to deal with the application, establishment or modification of the connection of an embedded generator to the distribution system.
>
> The AER seeks stakeholder comment on embedded generator connections undertaken by Aurora, specifically whether or not such connections should be classified differently to other connection services.

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 2.4.3.4, 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.[95]

- 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.[96]

The AER understands that 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. The AER understands that these by-laws only required customer contributions if the customer required more than two spans of service. [97]

New 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 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.[98]

Aurora has a suite of internal guidelines relating to customer connections.[99] One of Aurora's policies is to connect customers at least cost unless otherwise agreed to by the customer.[100] The AER also understands that Aurora is intending to revise its customer contribution guidelines prior to the commencement of the forthcoming regulatory control period.[101]

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.[102] 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

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95 OTTER, Response to information requested on 24 May 2010, submitted on 24 May 2010

96 Aurora, *Information Paper*, p. 15.

97 OTTER, Response to information requested on 27 May 2010, submitted on 27 May 2010.

98 Aurora, *Information Paper*, p. 15.

99 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.

100 Aurora, *Aurora network's customer capital contribution policy*, 11 May 2006, p. 5.

101 Aurora, Response to information requested on 25 May 2010, submitted on 25 May 2010.

102 Aurora, *Overhead electricity supply at low voltage*, p. 7.

- public road extension subsidy (extension of up to two spans of overhead power line along a public road or street).[103]

The AER understands that capital contributions can be apportioned where more than one customer is to be supplied by the augmentation.[104] The AER also understands that 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.[105] However, the AER further understands that Aurora recovers the cost of its subsidies through DUOS charges.[106]

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.

As noted earlier, the AER understands that 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.

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

[103] ibid., p. 7.
[104] ibid., p. 12.
[105] ibid., pp. 7–8.
[106] OTTER, Response to information requested on 27 May 2010, submitted on 27 May 2010.

previously classifying standard connection services as special services (regulated under a price cap) the costs of these are currently recovered through DUOS charges. However, 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.

- 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 are no other relevant factors that change 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 in this instance.

The AER is seeking comments on its preliminary position to classify standard connection services as standard control services.

Connections requiring augmentation

Clause 6.21.1 of the NER states that a DNSP may recover (amongst other prudential arrangements) a capital contribution from the customer where augmentation works are required to connect the customer to the distribution network (or modify their connection). Such prudential arrangements are a matter for negotiation between the customer and the DNSP. Clause 6.21.2 states that the DNSP is not entitled to recover any component of asset-related costs paid for by customers.

However, the AER notes that the NER prohibit the AER from classifying these capital contributions as a service because they are 'works'. As such 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. However, 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 the fact that connection services are a special service 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 control form of 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 augmentation works as a separate 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.[107]

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.[108] 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.[109] 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 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 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

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

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

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

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 are no other relevant factors that change 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.

The AER notes that pursuant to the prudential requirements in clause 6.21.2 of the NER, Aurora will not be entitled to a return of or return on capital contributions for augmentation works paid for by the customer.

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, the AER notes that the National Energy Customer Framework (NECF), which is currently being developed by the MCE, is scheduled for introduction into the South Australian Parliament during the spring 2010 sitting.[110]

State and territory Ministers have endorsed a set of policy positions that will underpin the legislation to give effect to the NECF.[111] 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.[112]

AER's preliminary position

The AER's preliminary position is 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. This is supported by the AER's assessment against the factors in clause 6.2.1 and 6.2.2 of the NER.

The AER notes that 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, is likely to provide more guidance to Aurora and customers on the determination and allocation of connection augmentation costs.

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110 Other jurisdictions are to apply the NECF progressively to fit their circumstances between July 2011 and July 2013.

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

112 ibid.

The AER seeks comment on these proposed classifications, particularly on the AER's approach to classifying connections requiring augmentation. The AER also seeks comments on how customers, particularly large customers, view Aurora's customer contributions policy and if there are any areas of particular concern.

2.4.3.6 Non-standard services

As noted in the discussion on other distribution special services (section 2.4.3.4), the AER understands that Aurora provides a range of non-standard services on a quoted fee 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
- above-standard 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).[113]

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. This means that Aurora must set individual prices for these services after they have been requested and after it has undertaken an assessment of the requested task. Put simply, it is not possible to set a generic total fixed fee in advance for these services.

Current classifications

As noted in the discussion for other distribution special services (section 2.4.3.4), OTTER has recognised the existence of non-standard special services, or 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 non-standard services.[114] Specifically, OTTER stated that:

> … in some circumstances the specification of a Service Type and fixed price is not always feasible. 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.[115]

OTTER therefore determined that it would:

[113] Aurora, *Information paper*, May 2010, p. 18.
[114] OTTER, *Maximum Prices for Special Services*, June 2008, p. 20.
[115] ibid., p. 23.

> …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.[116]

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'.

Issues and AER's considerations

In determining the appropriate classification for non-standard services the AER has first had regard to the form of regulation factors contained in section 2F of the NEL.

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 non-standard 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.

However, the AER has also had regard to clause 6.2.1 of the NER, and notes for the purposes of clauses 6.2.1(c)(2) and (3), non-standard services are not currently subject to any substantive form of regulation by OTTER. OTTER requires that Aurora publish its charge out rates, but does not require Aurora to submit them for approval by OTTER. The AER therefore considers that it was not OTTER's 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.

The AER also notes for the purposes of 2F(d) of the NEL, there may be an element of countervailing power on the part of the customer if non-standard services are aimed at larger customers (such as the Tasmanian government). In addition, Aurora's non-standard services have not been previously classified under the NER, so under clause 6.2.1(d) of the NER, there is a presumption in favour of a classification consistent with the previously applicable regulatory approach unless there is another classification that is clearly more appropriate.

The AER's preliminary position is that, on balance, having regard for the requirements of clause 6.2.1 of the NER, non-standard services should be unregulated.

[116] ibid, p. 20.

The AER notes that there may be merit in classifying non-standard services as alternative control services. The AER seeks stakeholder's views as to the appropriateness of its classification and whether there is sufficient reason to deviate from the approach most similar to that which it was previously subject to.

AER's preliminary position

The AER's preliminary position is that Aurora's non-standard services should be classified in a manner which is consistent with the previously applicable regulatory approach, as on balance, no other classification is clearly more appropriate. On this basis, these services should be unregulated.

2.5 AER's preliminary position on 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.

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 preliminary position 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
- all type 5, 6 and 7 metering services, excluding PAYG metering services and above standard metering services, will be classified as direct control services and further classified as alternative control services
- all PAYG metering services will remain unregulated
- above standard metering services will be unregulated
- public lighting services will 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 will 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 will be classified as direct control services and further classified as alternative control services

- non-standard services (quoted services) will be unregulated

- above standard network services will be unregulated.

The AER's preliminary position 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 preliminary positions set out in this paper aim 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.

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 preliminary positions set out in this paper provide for a smooth transition to the benefit of both Aurora and users, and does not impose unnecessary costs. Table 2.3 shows the AER's preliminary classifications for Aurora's distribution services.

Table 2.3 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 above 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.

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 are regulated under the negotiate/arbitrate framework set out in Part D of chapter 6 of the NER.

The AER's likely approach to the classification of Aurora's distribution services was discussed in chapter 2 of this paper.

3.2 Requirements of the NEL and NER

A distribution determination imposes controls over the prices of direct control services, and/or the revenue to be derived from direct control services.[117] 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.[118]

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.[119]

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[120]
- the basis of the control mechanism.[121]

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

[117] NER, cl. 6.2.5(a).
[118] NER, cl. 6.8.1(c).
[119] NER, cl. 6.12.3(c).
[120] NER, cl. 6.2.5(b).
[121] NER, cl. 6.2.6(a).

- a schedule of fixed prices
- caps on the prices of individual services (for example, a price cap or caps)
- caps on the revenue to be derived from a particular combination of services (for example, a revenue cap)
- a tariff basket price control (for example, a weighted average price cap)
- a revenue yield control (for example,. 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
- 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.[122]

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

[122] NER, cl. 6.2.6(a).

instead have regard to the potential for development of competition in the relevant market, and how the control mechanism might influence that potential.[123]

The control mechanism must have a basis specified in the distribution determination.[124] 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 need not, use a building block approach, and may, but need not, incorporate a pass-through mechanism.[125]

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 preliminary 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

OTTER's 2007 determination defined distribution network services provided by Aurora as:

> *…being the conveyance of electricity (from the connection point with the transmission system to the customer connection point with the transmission system to the customer connection point including entry services, use of system services and exit services, excluding any connection owned and maintained by the customer) including:*
>
> - *the undertaking of works or the provision of maintenance or repairs for the purposes of carrying out conveyance of electricity, and*
> - *the provision, installation and maintenance or repairs of any, switchgear or other electrical plant essential to the transportation and electricity of electricity.*[126]

The current control mechanism for distribution network services applied to Aurora is a revenue cap, where the basis of control is an incentive based variant of CPI–X using a building block approach.

In its 2003 distribution determination, OTTER decided that the building block, rather than a total factor productivity (TFP) approach should be used to calculate the annual

123 NER, cl. 6.2.5(d)(1).
124 NER, cl. 6.2.6(b).
125 NER, cl. 6.2.6(c).
126 OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania: final report and proposed maximum* prices, September 2007, pp. 14–15. (OTTER, *Final report*, September 2007)

revenue requirement.[127] The relative merits of both the building block and TFP approaches were assessed in the 2003 decision, where OTTER adopted the recommendation of their consultant (Farrier Swier)[128] that there was insufficient data available to develop an electricity TFP index to apply the TFP methodology. Therefore, a building block approach was considered the more appropriate method to calculate the aggregate annual revenue requirement (AARR).

Under the current revenue cap approach, OTTER determines the maximum revenue that can be earned from distribution network services through utilising the formula:

$$AARR_y = F_y \times PIF_y + \left[\begin{array}{l} \left(ESISC_y + NEMC_y + TMR_y + GSLse_y \right) \\ \times \,{}^{CPI_y}\!/_{CPI_{y-1}} \times \left(1 + WACC\right) \end{array} \right] + \\ + K_{y-p} + NEM_y \times {}^{CPI_y}\!/_{CPI_{y-2}} + FRC_y + TAXA_y + L_y + CapCon_y \\ + GSLcap_y + CF_y + O_y$$

Where, in simplified terms:

- *PIFy* is the prescribed inflationary factor
- F_y is the forecast maximum revenue
- $ESISC_y$ is the difference between the assumed and actual electrical safety inspection service charge
- $NEMC_y$ is the difference between the assumed and actual National Energy Market charge
- NEM_y represents the difference between the actual allowance approved by the Regulator and the forecast allowance in relation to Aurora Distribution's participation in the NEM and retail contestability costs
- TMR_y is an adjustment factor reflecting the cost of the State Government's Trunk Mobile Radio network
- CPI_y is the CPI for the quarter ending 6 months prior to the commencement of the period in question.
- *WACC* is 6.64 per cent.
- FRC_y is the allowance for the implementation of full retail contestability

[127] OTTER, *Final report*, September 2007, pp. 22–23.

[128] OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices*, September 2003, p. 27.

- TAX_{Ay} is the allowable tax event adjustment
- L_y is an adjustment for costs imposed due to changes in safety and/or environmental legislation
- $CapCon_y$ is an adjustment to the AARR arising from a change in Aurora's capital contribution policies
- $GSLcap_y$ is an adjustment for the cap on the Guaranteed Service Level scheme
- $GSLse_y$ is the adjustment arising from the making of single duration outage GSL payments to customers for where the threshold for payments was subsequently altered
- K_{y-p} corrects for the under-recovery or over-recovery of allowable revenues in prior years
- CF_y represents adjustments arising from the 2003 Determination
- *Oy* is an amount no more than ±2 per cent of the F_y for the relevant period.[129]

Calculating AARR and tariff determination

The pricing of distribution network services is comprised of two steps:

1. Determining the AARR through the application of the revenue cap formula and in accordance with the principles and objectives set out under the regulatory framework.
2. Calculating usage based prices for specific services. 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 regulated price cap and revenue.[130]

The 2007 price determination requires that Aurora must develop its network tariffs annually and submit them to OTTER each year for approval, in accordance with any guidelines by OTTER. OTTER has issued the *Approval of network tariffs in accordance with the 2007 determination guideline*, which, amongst other things:[131]

- requires Aurora to develop a network tariff strategy
- requires a network tariff pricing proposal for each year to be submitted at least 2 months before the start of the year

129 For a more detail of the components that make up the revenue cap see: OTTER, *Investigation into Electricity Supply Industry Pricing Policies, Declared electrical services pricing determination*, Issued 31 October 2007, as amended 10 December 2007.

130 OTTER, *Final report*, September 2007, p. 22.

131 ibid, p. 243.

- sets out the required content of the network tariff pricing proposal
- sets out the process for the approval of the network tariff pricing proposal by OTTER
- requires Aurora to provide details of existing network tariffs, and proposed price trends, on its website.

Network tariffs must also be developed in accordance with principles set out in Schedule 2 to the 2007 price determination, which in summary require:

- network tariffs to be uniform across mainland Tasmania for a particular customer class
- for each network tariff class, revenue to be recovered to between an upper (stand-alone) and lower (avoidable cost) band
- each charging parameter to take into account:
  - the long run marginal cost of the service or element of the service
  - having regard to transaction costs, fixed/variable proportions in other NEM jurisdictions, the appropriate allocation of costs associated with Aurora's participation in the NEM and retail contestability between contestable and non-contestable customers, and whether customers are likely to respond to price signals.

The above requirements are identical to those in clauses 6.18.5 and 9.48.4B of the NER.

The calculation of network tariffs is also required to take into account an adjustment for differences in prior years' revenue arising from differences between the forecast and actual customer numbers and loads. This adjustment can be significant—in 2009–10 there was a $10.2 million increase in revenue to make up for previous shortfalls, which is around 5 per cent of the forecast revenue base of $220.5 million.[132]

3.3.2 Issues and AER's considerations––standard control services

In section 2.5 the AER proposed to classify Aurora's distribution network services, standard connections, connections requiring augmentation and the previous public lighting distribution use of system (DUOS) charge as standard control services. The AER must apply a form of control to each of these standard control services. Accordingly, 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.

[132] OTTER, *Final report*, September 2007, p. 243.

The regulatory arrangements applicable in the current regulatory period

The fixed revenue cap control mechanism currently applicable to Aurora's prescribed services is described above in section 3.3.1 The basis of the control mechanism is an incentive based variant of CPI–X.

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 of the NER, will undertake a robust investigation into Aurora's forecast costs during the upcoming determination process to determine whether the forecast costs are reasonable

- the AER's preliminary position to apply an 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 TEC already places considerable boundaries in which Aurora operates, which includes an onus on the DNSP to adopt quality management and assurance procedures.[133] The AER also considers that the application of an incentive arrangement such as the STPIS will provide appropriate incentives for Aurora to focus on areas which have the potential to be of particular concern to customers, such as service performance.

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 preliminary position is that the potential impacts on incentives and risks are not sufficient to support a change form 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 proposed 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.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

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[133] TEC, clause 8.2.1.

- 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.

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 face the incentive to set inefficient tariffs under other forms of control, such as price caps, weighted average price caps and 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 has considerable influence in setting prices for standard control services through the approval of Aurora's pricing proposals to be made under clause 6.18.6 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 in section 3.3.2, the current control mechanism for distribution network services in Tasmania is a revenue cap. The AER's preliminary position 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. A weighted average price cap, an average revenue cap and a revenue cap are currently being applied in other NEM jurisdictions.

The AER's preliminary position is that 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, however, that it is desirable for the control mechanism to be consistently applied to similar services with each NEM jurisdiction. For this reason, the AER's preliminary 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. For that reason, the AER’s starting point for consideration of this issue in the current context is likely to impact of any change in form of control from the current regulatory control period to the forthcoming regulatory control period.

The AER’s preliminary position is that administrative costs are best minimised in this instance by maintaining, with any necessary alterations, the current form of control. The AER only intends to depart from the current form of control where there is evidence that such a departure is more appropriate.

Basis of a control mechanism for standard control services

For standard control services the AER must implement a control mechanism that is of the prospective CPI–X form made in accordance with Part C of the NER—using the building block approach.[134] The building block approach entails, the AER determining a DNSPs annual revenue requirement (ARR) for standard control services based on the following building block elements:

- indexation of the regulatory asset base
- the return on capital for that year
- the depreciation for that year
- the estimated cost of corporate income tax for that year
- the revenue increments or decrements (if any) for that year arising from the application of the efficiency benefit sharing scheme, the service target performance incentive scheme and the demand management incentive scheme

[134] NER, clause 6.2.6(a).

- the other revenue increments or decrements (if any) for that year arising from the application of the a control mechanism in the previous regulatory control period.

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.

3.4.1 Current regulatory arrangements for Aurora

3.4.1.1 Metering services

OTTER's 2003 determination established prices for metering services using an annuity approach based on meter replacement cost, operating (predominately meter reading) and capital costs. OTTER applied a higher rate of return to the meter stock (7 per cent) than the distribution asset base (6.61 per cent) to reflect the potential impact of technological change on asset lives. 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.

OTTER elected to take the same approach of applying an annuity model to metering services in its 2007 decision. 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. The 2007 decision applies the same rate of return (WACC) as that applied to network services. 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. The AER considers this current control mechanism for metering services is a price cap. The meter classes are:

- high voltage and high voltage sub-transmission current transformer meters
- high voltage /low voltage current transformer meters
- business low voltage single phase meters
- business low voltage multi—phase meters
- business low voltage—current transformation meters
- residential low voltage single phase meters
- residential low voltage multi—phase meters
- residential low voltage—current transformation meters

- other meters.

The AER has considered whether the current control mechanism for metering services could be interpreted as a price cap or a revenue cap, and has concluded that it is a price cap. The AER invites comment on this interpretation.

OTTER elected to utilise an annuity approach rather than a building block model to calculate the daily maximum meter allowance for metering services. OTTER had concerns over the use of a building block model as it considered there was some uncertainty about the ability to accurately to assess the age of the meter stock at the time, given the changing nature of the meter stock.[135] In its 2007 decision, OTTER also noted that the annuity approach would give an equivalent annual charge to that expected over the long-term from a building block approach using a depreciated optimised replacement cost (DORC) approach.[136]

OTTER's decision to adopt the annuity model was made in the context that Aurora intended to discontinue purchasing mechanical disc meters, with all new and replacement meters to be electronic. OTTER also noted that for the 2007 decision, Aurora was proposing an accelerated replacement strategy of mechanical to electronic metering. OTTER calculated that the difference in annuity costs between the new/replacement and accelerated approaches was relatively small. Hence OTTER calculated the maximum metering charge based on the new/replacement approach and left Aurora to make a business decision as to whether to adopt an accelerated program. In its 2007 proposal, Aurora noted its plan to discontinue purchase of mechanical disk meters and replace 27 000 existing meters with 15 000 electronic meters each year. The replacement strategy is expected to reduce the total number of meters from around 400 000 to 300 000.[137]

In the 2003 determination, the daily allowance per meter for classes HV business, LV business and residential was calculated from forecast costs and forecast number of meters in each class.[138] The annuity model employed in the 2007 determination was consistent with the model specified in the 2003 decision, and assumed that Aurora would maintain the current fleet of mechanical meters for the duration of their life and then replace them with electronic meters. In the 2007 determination, it was acknowledged by OTTER that the meter supply and installation costs have declined over time as a result of improvements in technology and increased labour productivity.

The nature of meter stock over the regulatory control period has also changed, with traditional PAYG meters being replaced by a base standard electronic meters with a Payguard unit attached. The Payguard unit can be detached so that the electronic meter becomes a standard electronic meter. The base standard meter can earn a rate of return as part of Aurora network's distribution asset base. The Payguard unit is the

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135 ibid., p. 263.
136 ibid.
137 ibid., p. 267.
138 ibid., p. 263–264.

property of Aurora Retail and will not earn a rate of return.[139] The conversion of the current integrated prepayment meters to electronic meters is the main factor driving the change in the nature of the meter stock.[140]

3.4.1.2 Public lighting

Aurora operates and maintains the public lighting system throughout Tasmania on behalf of councils and other government road authorities. Service standards for public lighting are addressed in Aurora's network customer charter.[141] 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 the 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. [142]

Public lighting in Tasmania does not fall under the definition of any of the declared services and hence is not regulated by OTTER. OTTER has not been able to conclude, as required by section 19 of the price control regulations, that the promotion of competition, efficiency or the public interest requires the making of the declaration.

Aurora has advised that it has used a building block model to develop charges for its public lighting services.[143] This involves taking the replacement value of each light type and calculating the return and depreciation for each asset type using an annuity formula. The annuity calculation is then added to the estimated operation and maintenance costs for each light type to estimate the total annual charge. Through the revenue cap for distribution network services a street lighting DOUS charge is calculated which is applied to public lighting services. The street lighting DUOS charge is also calculated for each light type that reflects each light type's estimated kWh consumption. The annual DUOS and annuity charges are added to arrive at a total annual charge, which is then converted to a monthly fixed fee. It is also worth noting that there is a mixture of ownership arrangements for the provision of public

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139 ibid., p. 264.
140 ibid.
141 Aurora, *Electricity network customer charter,* http://www.auroraenergy.com.au/electricity_network/network/electricity_network_distribution_charter.asp, p.5.
142 Aurora, *Information paper for the AER: Services, Classifications and Control Mechanisms*, May 2010, p. 35.
143 ibid., p. 8.

lighting services in Tasmania. As such, Aurora's calculation of public lighting charges is only based on public lighting assets that are owned by Aurora.[144]

3.4.1.3 Special services

Arrangements for the regulation of special services were not finalised at the time of the 2007 determination—Aurora's submission on special services was only lodged in July 2007 and by September 2007, information requested from Aurora was still forthcoming. Hence it was necessary for OTTER to undertake further work on the approach to be taken to special services. Its decision on regulation of these services was made in June 2008, with the determination issued on 1 July 2008.[145]

OTTER was clear that:

> *Separating Special Services from distribution network services in the Determination was done with the explicit intention of regulating their maximum prices by way of a price cap. A price cap mechanism is considered appropriate for these types of services, ie those which are provided directly to the benefit of a specific customer, as the costs of providing these Special Services are primarily volume driven. Further, to facilitate the separate regulation of these services, the cost of providing these Special Services was excluded from the calculation of the maximum revenues for distribution network services and maximum prices for metering services.* [146]

OTTER considered that a number of options could be implemented for the regulation of special services.[147] These included a variety of options from no price controls to explicit price setting, monitoring or approval or a price control.

OTTER elected to regulate a reference set of special services by using a price cap mechanism for a reference set of three categories of special service types and their initial maximum prices which were determined by OTTER. The approach:

- defined a notional maximum revenue of approximately $1.6 million which may be earned from the reference set of special services. (There is no subsequent catch-up if actual revenue exceeds or falls short of the notional maximum.)
- escalated the notional maximum revenue by the ABS labour price index
- defined a fixed 'weighting' for each of the service types, that is,. the number of services likely to be provided, multiplied by the proposed charges, must not exceed the notional maximum revenue
- enabled Aurora to amend or modify the list of its special services over time by advising OTTER as part of its annual pricing proposal. There are few formal

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144 ibid.

145 OTTER, *Final report*, September 2007, p. 268.

146 OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania: Supplementary final report and statement of reasons on maximum prices for special services provided by Aurora Energy*, June 2008, p. vii (OTTER, *Maximum prices for special services,* June 2008).

147 ibid., p. 7.

limitations on the services that can be added, other than they must comply with the relatively broad definition of 'special distribution services'.

Due to the basis of the development of charges for special services, the AER has considered whether the current control mechanism for special services could be interpreted as a price cap, a revenue cap or a weighted average price cap form of control, and has concluded that it is a price cap. The AER invites comment on this interpretation.

Table 3.1 below sets out the services types and number of services established in the July 2008 determination:

Table 3.1 Service types and number of services established in the July 2008 determination

Service type	Number of services (weighting)
Energisation, de-energisation, re-energisation	
disconnections	17 000
transfer of supply	13 600
reconnections	10 500
same day reconnections	800
check reads	1 200
sub tenant read	200
Meter alteration	
add circuit (meter)	260
alter circuit (meter)	1 360
Meter test	
single phase meter	90
three phase meter	20
current transformer meter	5

Source: OTTER, *Maximum prices for special services,* June 2008, p.13.

The other categories of special services (other distribution special services) do not form part of the price caps and OTTER elected to require simply that these other special services and their prices be provided to OTTER as part of the annual pricing process and therefore were not subject to a form of control mechanism. The AER notes that even within the categories set out above some prices for individual services do not fall within the price cap mechanism on the basis that there is no defined weighting for them.

OTTER elected to take such an approach on the basis that:

- there was no documented evidence that existing charges for these services were excessive or that Aurora had been abusing its (effective) monopoly power

- it is not possible, or practical, to set a fee or charge for every possible type of service and hence it may not be possible to eliminate all cross-subsidies.[148]

A key objective for OTTER was to improve the transparency of special services and their prices, and to give Aurora some flexibility over prices as they worked to better define special services over time.[149] This was the reasoning behind placing a price cap on the reference set of special services.

An example of the operation of the reference set special services price cap can be seen in Aurora's application for approval of its 2009–10 special services.[150] For the 2009−10 pricing approval, Aurora proposed six charges under the energisation, de-energisation, re-energisation category, five charges under the meter alteration category and four charges under the meter test category.

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

For the reasons set out in chapter 2, the AER's preliminary position is that the following distribution services should be classified as alternative control services:

- all type 5, 6 and 7 metering services, excluding PAYG metering and above standard metering services
- all public lighting services—repair, replacement and maintenance; alteration and relocation; and provision of new public lighting
- all special services—reference set special services and other special services

The following sub-sections set out the matters that the AER must have regard to in selecting the appropriate control mechanism.

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.

The price cap control mechanism that currently applies to Aurora's reference set of special services are now grouped as fee based services and is described in section 3.4.1.3 of this paper. Further, the AER's preliminary position is to:

- continue to apply a price cap for all type 5, 6 and 7 metering services, excluding PAYG metering and above standard metering services

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148 OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania: Supplementary draft report and statement of reasons on maximum prices for special services provided by Aurora Energy*, April 2008, p.18 OTTER, *Maximum prices for special services,* June 2008, pp. 19–20.

149 OTTER, *Maximum prices for special services,* June 2008, p. 1.

150 Aurora, *Distribution special services: Prices for the provision of distribution special services for the period 1 July 2009 until 30 June 2010*, Submission to the Energy Regulator April 2009.

- commence the application of a price cap for 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 and to be regulated as fee based services

The reasons for this preliminary position are explained in the following sub-sections.

The influence on the potential for development of competition

The AER considered the potential for competition as part of classifying Aurora's direct control services as either standard or alternative control services in chapter 2 of this paper. The AER's assessment was that there is very little prospect for the development of competition in the provision of the services that it proposes to classify as alternative control services.

The AER considers that the application of a price cap control mechanism for all type 5, 6 and 7 metering services, excluding PAYG metering and above standard metering services and all special services, will not have any material impact on the competition for alternative control services or impede the potential to develop competition for these services.

As explained in section 2.4.3.3, the provision of public lighting services is currently unregulated. The AER acknowledges that the majority of the public lighting services provided in Tasmania are undertaken by Aurora. Whilst the AER considers it uncertain whether there is the potential for the development of competition in the various public lighting services in the forthcoming regulatory control period, the AER contends that applying a price cap to each of the public lighting services would provide more transparency and a greater breakdown of public lighting charges. This would 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. The AER acknowledges that there are barriers to entry other than competitive prices deterring third parties from providing these public lighting services.

Administrative costs

Clause 6.2.5(d)(2) of the NER requires the AER to consider the possible effects of the control mechanism on the administrative costs of the AER, Aurora and users or potential users. A control mechanism should aim to minimise the complexity and administrative burden for the AER, Aurora and users or potential 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 for all parties, and reduced compliance costs for Aurora.

Given the AER's proposed control mechanism for all type 5, 6 and 7 metering services, excluding PAYG metering and above standard metering services, is the same as that which currently applies, the AER does not consider that the implementation of price caps for these services will impose significant additional administrative costs on the AER, Aurora and users or potential users.

With respect to the preliminary position of applying price caps to all fee based special services, the AER notes that a price cap is currently applied to the reference set of special services. However, as discussed in further detail below, with the grouping of the other distribution special services with the reference set special services the AER's preliminary position is to modify the basis of control for setting the price caps for these special 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 create greater cost reflectivity for the charges of these services and more appropriate charges to end users in a user-pays environment which the AER considers warrants a short term increase in administration costs.

The AER's proposed classification of public lighting services as an alternative service and the application of a price cap mechanism would not substantially increase the administrative burden for the AER, Aurora, or end users. The AER intends to draw on and develop the building block model currently used by Aurora for the calculation of public lighting charges. The AER would assess the cost inputs into the model to ensure that revenue would be reflective of efficient costs. The AER also notes that the separate application of a price cap to each of the public lighting services would also increase the transparency in the calculation of public lighting charges.

On this basis, the AER considers that, with regard to administrative costs, establishing a price cap form of regulation for public lighting services, and continuing the respective price caps for all type 5, 6 and 7 metering services, excluding PAYG metering and above standard metering services, and all fee based special 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.

The AER notes that different forms of control are applied across the NEM jurisdictions to excluded distribution services, which are most likely to be classified as alternative control services. For example, in Victoria, non-contestable excluded services are regulated through a price cap, with no automatic escalation applied to these prices. In New South Wales and Queensland, a variant of a schedule of fixed prices is applied to excluded 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 considers 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 notes 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 does not find it inappropriate to classify all type 5, 6 and 7 metering services, excluding PAYG metering and above standard metering services, all fee based special services and all public lighting services as alternative control services and apply respective price caps.

AER's position on the basis of control for alternative control services

The AER is able to apply a control mechanism to a DNSP's alternative control services using chapter 6, Part C of the NER, which involves applying the building block approach, although it may elect to only apply certain elements of the building block approach. Alternatively, the AER may elect to implement a control mechanism that does not use the building block approach.

The AER proposes to apply a price cap form of control to regulate all alternative control services for the forthcoming regulatory control period. As stated in the NER, the basis of control for the respective alternative control services will be finalised in the distribution determination.[151] However, the AER considers it appropriate to provide its preliminary position on the basis for the respective alternative control price caps.

In regard to metering services, the AER's preliminary 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.

In regard to all special services, the AER considers that the current basis of control for the reference set special services, which utilises a formula based approach using a notional revenue cap combined with fixed weightings of services, may not promote cost reflective charges to customers. The AER notes that several of the distribution charges for the reference set special services in the current and previous regulatory control periods have not been accurately reflected by Aurora Retail in their respective charges to consumers.[152] The AER further notes that OTTER recognised that the adoption of cost reflective charges (assuming Aurora's charges were cost reflective) by Aurora Retail would incur price shocks by end users.[153] OTTER notes that for non-contestable customers that it may not be apparent that there is a distinction between "Aurora" as the distributor and "Aurora" as the retailer.[154]

The AER considers that the passing on of cost reflective charges by retailers to end users is beyond the scope of this preliminary positions framework and approach paper. However, the AER does note that the current basis of control applied to special

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151 NER, cl. 6.2.6(b).
152 OTTER, *Maximum prices for special services,* June 2008, p. 22.
153 ibid., p. 20.
154 ibid., p. ix.

services may give rise to cross-subsidisation among the reference set of special services provided by Aurora. As such, the AER is concerned that special service prices may not be cost-reflective and distort the charges set by Aurora Retail.

The AER notes that the current formula applied to special services was adopted by OTTER to provide Aurora with the flexibility to amend or modify its special services schedule when circumstances change.[155] The AER also acknowledges OTTER's decision to reduce the number of categories of special services so that customers could easily understand the separate charges as well as the grouping of similar services and the setting of average fees as an efficient mechanism for the recovery of the cost of these services.[156] Under this approach, OTTER confirmed that Aurora would at an aggregate level earn total revenues to recover the total cost of providing these services.

However, the AER notes that the current basis of control for the reference set special services allows Aurora to set and rebalance individual charges to meet a notional maximum revenue. This formula based approach allows the ability for Aurora to charge below cost for some services and well above cost for other services as long as it does not breach the notional maximum revenue. This basis of control can create a situation where the individual charges are not cost reflective. OTTER acknowledges 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.*[157]

The AER considers that a basis of control which allows price to exceed cost for one service and below cost for another service does not encourage cost-reflective prices, overall. OTTER acknowledged this point and stated:

> *Special Services generally represent those services that are provided for the benefit of a single customer rather than uniformly supplied to all network customers.*[158]

The AER considers that the benefit of a below cost charge for a special service provided to one single customer should not be at the expense for an excess charge to another customer for the provision of a different separate special service.

Therefore, the AER's preliminary position for all special services is to depart from the current basis of control for the reference set special services which uses a formula approach using a notional revenue cap combined with fixed quantities. Instead, the AER proposes to set individual prices with a price path over the forthcoming regulatory control period.

The AER notes that the proposed change in basis of control for all special services will still allow the amendment and modification of the special service charge schedules. This will continue to offer Aurora flexibility in the forthcoming regulatory control period, should its operating circumstances change. This was a concern of

155 ibid., p. 20.
156 ibid., p. 22.
157 ibid., p. 22.
158 ibid., p. 1.

OTTER in its 2007 decision and a contributing factor in applying the current formula based approach to the reference set special services. Additionally, the AER considers its preliminary position on the special services basis of control is consistent with OTTER's views to move to a more transparent user-pays fee system and to better define special services over time.[159]

The AER invites comment on the preliminary position of the basis of control for all special services.

In regard to all public lighting services, the AER's preliminary position, is to apply a price cap form of control. This represents a departure from the existing regulatory arrangements, where public lighting services are currently unregulated. The AER notes that the price cap mechanism is an appropriate form of control as it would promote greater transparency and cost reflective prices for each of the public lighting services. To this extent the AER proposes to establish price caps on both fee-based (repair, replacement and maintenance services) and quoted (alterations, relocations and provisions of new) public lighting services. However, the AER will require further clarification of the cost escalation methodology assumed in Aurora's current building block model, for the purposes of determining the appropriate basis of control to be applied for public lighting services in the forthcoming regulatory control period.

The AER invites comment on its preliminary position forms of control and basis of control for public lighting services.

Aurora will be required to submit to the AER for approval an initial pricing proposal for the first year of the forthcoming regulatory control period and an annual pricing proposal for each subsequent year of the period. Such applications will need to cover alternative control services and be prepared in accordance with Part 1 of chapter 6 of the NER.

3.5 AER's preliminary position on the form of control mechanisms

3.5.1 Standard control mechanism

The AER's preliminary position is to 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. The AER's preliminary position is based on the following consideration which it 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[160] and connection services and is one of the control mechanisms listed in

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159 ibid., p. 1.
160 NER, cl 6.2.5(c)(3).

clause 6.2.5(b) of the NER that can be applied in the forthcoming regulatory period.[161]

- 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.[162]

- 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.[163]

- Retaining the current form of control for standard control services maintains consistency in the regulation of those services across Tasmania.[164] The AER consider 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.[165]

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.

3.5.2 Alternative control mechanism

The AER's preliminary position is to apply price cap regulation in the forthcoming regulatory control period to:

- 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 and to be regulated as fee based services.

The AER's preliminary position is based on the following considerations it has had regard to in accordance with clause 6.2.5(d) of the NER:

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161 NER cl. 6.2.5(b)(3).
162 NER, cl 6.2.5(c)(5).
163 NER, cl 6.2.5(c)(1).
164 NER cl. 6.2.5(c)(4).
165 NER cl. 6.2.5(c)(1).

- 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.[166]

- 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.[167] 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 type 5, 6 and 7 metering services, excluding PAYG metering and above standard metering services maintains consistency in the regulation of those services across Tasmania and over regulatory periods and is consistent with the form of regulation applied in some other NEM jurisdictions.[168]

- The AER has had regard to current regulatory arrangements and have considered that there are appropriate reasons (discussed above) for changing or commencing regulation of public lighting services and other distribution special services in the forthcoming regulatory control period through determining these services are alternative control services and applying a price cap.[169]

- Incorporating other distribution special services with the reference set of special services ensures that all special services are regulated by a consistent form of control (price cap).[170] A price cap for metering services and public lighting services will also allow a consistent form of control to be applied to these groups of services and although not required, maintains a consistent form of control applied to all alternative control services.

- The AER considers the retaining the current form of regulation (price cap) for the all type 5, 6 and 7 metering services, excluding PAYG metering and above standard metering services and the incorporation of the reference set of special services, with other distribution special services and will have limited if any additional administrative costs to the AER, Aurora and users or potential users in the forthcoming regulatory control period. Whilst the AER's preliminary position is to commence the regulation of public lighting services, the AER notes that the basis for regulating of these services is unlikely to change from Aurora's current process (using a building block approach) and therefore any material additional administrative costs to the AER, Aurora and users or potential users are currently unforeseen..[171]

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166 NER cl. 6.2.5(b)(2).
167 NER cl. 6.2.5(d)(1).
168 NER cll. 6.2.5(d)(3) and 6.2.5(d)(4).
169 NER, cl. 6.2.5(d)(3).
170 NER, cl. 6.2.5(d)(4).
171 NER, cl. 6.2.5(d)(2).

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.

4 Service target performance incentive scheme

4.1 Introduction

This chapter set outs the AER's preliminary position on its 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 Requirements of the NER

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.[172] 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.[173]

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. The AER developed the STPIS in accordance with this requirement.[174] The AER also had regard to the factors that the AER must have regard to, under clause 6.2.2(3) of the NER, in implementing the STPIS. The AER sets out the objectives of the STPIS in section 1.5 of the STPIS. These objectives align with the requirements for developing and implementing the STPIS under the NER.

The AER's objectives are that the STPIS:

172 NER, cl. 6.3.2(a)(3).
173 NER, cl. 6.8.1(b)(2).
174 NER, cl. 6.6.2(a).

(a) is consistent with the national electricity objective in section 7 of National Electricity Law (NEL)

(b) is consistent with clause 6.6.2(b)(3) of the NER which requires that in developing and implementing a service target performance incentive scheme, the AER must take into account:

(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

(2) any regulatory obligation or requirement to which the DNSP is subject

(3) the past performance of the distribution network

(4) any other incentives available to the DNSP under the Rules or a relevant distribution determination

(5) 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

(6) the willingness of the customer or end user to pay for improved performance in the delivery of services

(7) the possible effects of the scheme on incentives for the implementation of non-network alternatives

(c) promotes transparency in:

(1) the information provided by a DNSP under this scheme to the AER

(2) the decisions made by the AER. [175]

The national distribution STPIS (version 1.2) was released in November 2009 following a period of public consultation in accordance with the distribution consultation procedures under clause 6.16 of the NER. The STPIS can be found at the AER's website at http//www.aer.gov.au.

[175] AER, *Electricity distribution network service providers service target performance incentive scheme*, November 2009, p. 2. (AER, *STPIS*, Nov 2009)

4.3.1 Structure of the STPIS

The STPIS has four components:

1. Reliability of supply 2. Quality of supply 3. Customer service	} **S-factor**
4. Guaranteed service levels (GSL)	

These components can apply in isolation, or in combination with each other, within a distribution determination.

4.3.2 S-factor

The s-factor is the percentage revenue increment or decrement that applies in each regulatory year. Only the first three components of the STPIS contribute to the s-factor. Application of one or more of these three components takes the form of a financial reward or penalty for exceeding or failing to meet predetermined service targets. The s-factor component is symmetrical as penalties are incurred at the same rate as rewards. Under the STPIS, the maximum increment or decrement to revenue is ± 5 per cent of revenue. Aurora may propose a different revenue at risk where this would satisfy the objectives of the scheme.

Reliability of supply component

Three parameters are available under the reliability of supply component of the AER's STPIS:

- unplanned system average interruption duration index (SAIDI)
- unplanned system average interruption frequency index (SAIFI)
- momentary average interruption frequency index (MAIFI).[176]

Performance targets for these parameters are usually based on a DNSP's average historical performance over the previous five years.[177] Targets for each parameter are set for segments of the distribution network identified, for example, by feeder type.

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176 SAIDI refers to the sum of the duration of each sustained customer interruption (in minutes) divided by the total number of distribution customers. SAIFI refers to the total number of sustained customer interruptions divided by the total number of distribution customers. MAIFI refers to the total number of customer interruptions of one minute or less, divided by the total number of distribution customers.

177 This data is adjusted where necessary to account for improvements in reliability which have been included in the DNSPs expenditure program, and adjusted for any other material factors expected to affect network reliability performance.

This allows the STPIS to recognise variations in performance across a DNSP's network.

The incentive rates for this component, which are used in calculating the s-factor, are based on the value that customers place on reliability of supply, that is, the value of customer reliability (VCR) determined in the STPIS.

Quality of supply component

There is no quality of supply component included in the STPIS at this time.

Customer service component

There are four available parameters in the customer service component of the STPIS:

- telephone answering
- streetlight repair
- new connections
- response to written enquiries.

Of these, the STPIS provides that telephone answering will be included as a parameter for each DNSP to which the customer service component applies. One or more of the remaining parameters may apply under the customer service component where application of that parameter would satisfy the objectives of the scheme.

As with reliability of supply component of the STPIS, customer service parameter performance targets are based on average performance over the most recent five years of available data. Unlike targets for the reliability of supply component, targets for this component apply to the distribution network as a whole, and are not segmented.

The maximum revenue at risk for all customer service parameters in aggregate is ± 1 per cent of a DNSP's revenue for each year of the regulatory control period. The maximum revenue at risk for any individual customer service parameter is ±0.5 per cent of revenue for each year of the regulatory control period.

Under clause 5.3.2(a)(1) of the STPIS, the incentive rate for the telephone answering parameter is set at either minus 0.04 per cent per unit or a value determined from an applicable assessment of the value that customers attribute to the level of service proposed.

4.3.3 Guaranteed service levels

The purpose of the GSL component of the scheme is to provide payments directly to customers if the level of service experienced by them falls below the performance thresholds specified in the STPIS. The GSL component can operate independently or concurrently with the s-factor component of the scheme. The AER will only apply the GSL component of its STPIS to DNSPs that are not currently subject to a jurisdictional GSL scheme.

4.3.4 Reporting arrangements

Under the STPIS a DNSP must report to the AER annually on its performance against the parameters applicable to it under its current distribution determination. The DNSP must also provide detail of each of the exclusions applied under the scheme. This information will be collected through the use of an annual regulatory information instrument.

4.4 Implementing the STPIS

The national STPIS is designed to facilitate consistent application of a service performance incentive framework across the NEM, but can be implemented taking into account the circumstances of each DNSP.

In implementing the notional 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. [178]

In implementing the notional STPIS, the AER must also:

- consult with the authorities responsible for the administration of relevant jurisdictional electricity legislation[179]
- 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

[178] NER, cl. 6.6.2(3).
[179] NER, cl. 6.6.2(b)(1).

standards and service targets (including GSLs) as specified in jurisdictional electricity legislation.[180]

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 affect and is consistent with the NER requirements.

By basing the STPIS on existing jurisdictional schemes, 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 application to take account of transitional issues and the circumstances of DNSPs given their particular operating environments.

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

[180] 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.

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 ±0.5 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 Application of the STPIS in other jurisdictions

It is useful to examine the application of the STPIS in other jurisdictions to provide context regarding the application of the STPIS to Aurora.

In its recent distribution determinations for Energex, Ergon and ETSA utilities the AER decided to apply the s-factor component of the national STPIS. The AER's draft determination for the Victorian DNSPs also proposes to apply the s-factor component of the STPIS. The AER did not apply the GSL component of the national STPIS in Queensland and South Australia as jurisdictional GSL schemes apply in these jurisdictions. A similar approach is proposed in Victoria as a GSL scheme currently exists in Victoria. The AER did not apply the STPIS to the NSW DNSPs as reliable historical data was not available upon which to base performance targets. However, the AER implemented a paper trial of the scheme in NSW and the ACT.

4.5.1 Queensland

In the determinations for Energex and Ergon, the AER decided to apply the SAIDI and SAIFI reliability of supply parameters. Separate targets were set for the CBD, urban and rural sections of the networks in accordance with the definitions under the STPIS. The MAIFI parameter was not applied as Energex and Ergon were are unable to collect reliable MAIFI performance data. The only customer service parameter the AER decided to apply was the call answering parameter. [181] The AER did not apply the national GSL scheme as a jurisdictional GSL scheme currently applies to the Queensland DNSPs.[182]

[181] AER, *Final decision Queensland distribution determination 2010–11 to 2014–15*, May 2010, p. 281.

[182] AER, *Preliminary positions Framework and approach paper Application of schemes Energex and Ergon Energy 2010–15*, June 2008, p. 18.

The AER decided to apply a maximum revenue at risk under the scheme that applied to the Queensland DNSPs of ± 2 per cent.[183] This was because Energex and Ergon have not previously operated under a scheme that places a proportion of revenue at risk and Queensland specific transitional arrangements under clause 11.16.5(3) of the NER required consideration of a lower powered incentive. The AER also noted that in implementing similar service incentive schemes, apart from in Victoria, jurisdictional regulators typically started with a revenue at risk of around 1–2 per cent.[184]

4.5.2 South Australia

The AER applied the reliability of supply and customer service components of the STPIS to ETSA Utilities in the 2010–15 regulatory control period. Under the reliability of supply component, the AER set targets for both SAIDI and SAIFI, with financial incentives attached to each. The AER set separate targets for the CBD, urban, and rural sections of ETSA's network in accordance with the definitions in the STPIS.[185] The AER did not apply the MAIFI parameter as the AER did not consider that the sampling method used in ETSA Utilities' reporting of MAIFI provided a suitable basis of performance measurement for a financial incentive such as the STPIS.

The AER applied the telephone answering customer service parameter to ETSA Utilities. The AER did not apply the GSL component of the national STPIS as a jurisdictional GSL scheme administered by ESCOSA currently applies.[186] The revenue at risk for ETSA was set at ±3 per cent including ±0.3 per cent for the telephone answering parameter.[187] The AER decided to apply a ±0.3 per cent level of revenue at risk given the uncertainty in calculating ETSA utilities Major Event Day (MED) threshold.[188]

4.5.3 NSW and the ACT

The AER elected to apply its STPIS by way of a paper trial to the NSW DNSPs in the 2009–14 regulatory control period. In implementing a STPIS to the NSW DNSPs the AER decided that it should not apply a scheme with revenue at risk primarily due to concerns with data availability and accuracy, and the implications for design of an appropriate scheme with financial impacts in the limited time available.[189]

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183 AER, *Final decision Queensland distribution determination 2010–11 to 2014–15*, May 2010, p. 282.

184 AER, *Preliminary positions Framework and approach paper Application of schemes Energex and Ergon Energy 2010–15*, June 2008, p. 16.

185 AER, *Final decision South Australia distribution determination 2010–11 to 2014–15*, May 2010, p. 201.

186 AER, *Preliminary positions Framework and approach paper ETSA Utilities 2010-15*, June 2008, p. 18.

187 ibid, p.75

188 AER, *South Australia Draft distribution determination 2010–11 to 2014–15*, Nov 2009, p. 354.

189 AER, *Service target performance incentive arrangements for the ACT and NSW 2009 distribution determinations*, Feb 2008, p. 15.

Under the transitional rules in chapter 6 of the NER[190] the AER could not apply a STPIS with financial rewards or penalties to ActewAGL without its agreement. ActewAGL did not support the application of a scheme with revenue at risk, and as a result a paper trial was applied.

4.5.4 Victorian Draft Determination

In its draft determination the AER proposed to apply the reliability and customer service components of the s-factor to the Victorian DNSPs. The draft determination applied all the supply reliability parameters, but applied a different definition of MAIFI that was consistent with the definition of MAIFI that applied under the ESCV's scheme. The AER applied the telephone answering customer service parameter.[191]

In the draft determination the AER applied the default maximum revenue at risk of ±5 per cent to all the DNSPs apart from SP AusNet. SP AusNet requested an uncapped s-factor scheme. The AER did not consider it appropriate to apply a uncapped scheme as an uncapped scheme has the potential to expose customers to significant price fluctuations that may outweigh the benefits the heightened performance incentive. Instead the AER proposed to apply a maximum revenue at risk of ±7 per cent of revenue.[192]

4.6 Overview of the current and previous service incentive arrangements in Tasmania

4.6.1 Previous regulatory control period 2003–06

As part of its 2003 regulatory determination for Aurora, OTTER implemented an incentive scheme that penalized Aurora for failing to meet predetermined SAIDI and SAIFI targets for service performance. Conversely the scheme rewarded Aurora for bettering the targets. The incentive regime 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. Unlike the national STPIS, performance targets under the Tasmanian scheme were set for SAIDI and SAIFI parameters for the entire network. Similar to the national STPIS, the Tasmanian scheme applied a cap on revenue at risk and excluded the effects of MED days.[193] Unlike the national STPIS these targets were not broken down further into individual geographical targets. This was the first financial performance incentive scheme implemented in Tasmania.

SAIDI and SAIFI targets were set based on input by Aurora, and analysis from OTTER's consultants PB Associates. A baseline for 2003–06 was set using a historic

190 clause 6.2.2(k) of the transitional chapter 6 rules of the NER.

191 AER, *Victorian electricity distribution network service providers Distribution determination 2011–2015*, June 2010, p. 693.

192 ibid., p.643

193 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)

24 month rolling average, with explicit adjustments made to future year targets as a result of network upgrades.[194]

In the 2003–06 regulatory control period a GSL scheme 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.[195]

Under the performance incentive scheme, Aurora failed to meet the targets and was penalized in each year of the 2003–07 regulatory control period. Table 4.1 outlines the outcomes of the scheme. In total Aurora was penalized $4.7 million ($2002) under the scheme. 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.[196] Table 4.2 outlines the payments under the Tasmanian GSL scheme in that control period.

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

194 ibid., p. 116.
195 ibid., p. 126.
196 OTTER, *Draft Position Paper Service Incentive Scheme*, May 2007, p. 32.

Table 4.2 Payments under the Tasmanian GSL scheme 2003–06

		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.

4.6.2 Current regulatory control period 2008–12

OTTER released a released a Draft Position Paper on the service incentive arrangements to apply to Aurora in the 2008–12 regulatory period in May 2007.[197] Subsequently, OTTER released a draft[198] 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 the service incentive arrangements that would apply to Aurora in the 2008–12 regulatory control period. [199]

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 s-factor scheme. The positions adopted in the Draft Position Paper were broadly applied in OTTER’s draft report and final report on the maximum prices that Aurora can charge for its services.

As proposed in the Draft Position Paper, in its final decision OTTER decided not to apply an s-factor 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: [200]

- 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

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197 ibid.

198 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)

199 OTTER, *Final Report*, Sep 2007, p. 225.

200 OTTER, *Draft Position Paper Service Incentive Scheme*, May 2007, p. 61.

- 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

As there was uncertainty as to the appropriate starting point for the scheme, OTTER was concerned that Aurora could be arbitrarily penalised or rewarded through the application of the scheme. On the other hand, OTTER acknowledged the risk that without an incentive to maintain average performance, Aurora may reduce network maintenance and diligence in operations leading to deteriorating reliability. OTTER considered that his risk could be counteracted by publicly reporting on service performance providing Aurora with an incentive to maintain and improve performance. On balance, OTTER considered that it would be more appropriate to report on network reliability standards rather than apply a service incentive scheme to Aurora in the 2008–12 control period.[201]

In its final report, 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.[202] This was consistent with the position adopted in the Draft Position Paper.

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).[203] The working group developed the reliability standards with the intention of using them as the basis 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.[204]

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

201 ibid, p. 64.
202 OTTER, *Final Report*, Sep 2007, p. 223.
203 OTTER, *Draft Report*, July 2007, p. 195.
204 OTTER, Aurora, OEPC, *Joint Working Group Final Report, Distribution Network Reliability Standards, Volume I – Summary of Recommendations and Overview*, Feb 2007, p. 2.

precluded differentiation of varying types of loads on a single feeder; for example a feeder classified as rural may also supply regional centres of urban fringes as well as a significant rural load.[205]

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.[206]

These supply reliability standard and community categorisations were incorporated into the Tasmanian Electricity Code (TEC). Clause 8.6.11 *Interruptions to supply* of the TEC outlined the minimum supply reliability standards that apply to communities within Tasmania. Table 4.3 below outlines the minimum service standards in the TEC.

Table 4.3 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 times the GSL allowance would be appropriate,[207] but in response to a submission from Aurora OTTER agreed in its final decision to a cap of 2 times the GSL allowance.[208]

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.[209] 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.[210] In its final report OTTER determined that the

205 ibid., p. 7.
206 OTTER, *Draft Position Paper Service Incentive Scheme*, May 2007, p. 21-22.
207 OTTER, *Draft Report*, July 2007, p. 196.
208 OTTER, *Final Report*, Sep 2007, p. 234-235.
209 OTTER, *Draft Report*, July 2007, p. 196.
210 OTTER, *Final Report,* Sep 2007, p. 235.

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. [211]

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.[212]

In addition, because the GSL scheme operated on a rolling 12 month period (and not a calendar or financial basis) transitional arrangements for funding were put in place. OTTER believed that a rolling year approach is better than a financial year approach as it is irrelevant to a customer whether interruptions occur within or across financial years.

OTTER agreed that the existing list of exemptions under the GSL scheme should continue.[213] The GSL payments under the new scheme are outlined in Table 4.4 and Table 4.5. 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 are applied to single outage durations for each community with penalty payments of $80 for the first threshold and $160 for the second threshold.[214]

Table 4.4 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.

[211] ibid., p. 235.
[212] ibid., p. 232.
[213] ibid., p. 234.
[214] OTTER, *Guaranteed Service Level (GSL) Scheme*, Dec 2007, p. 6.

Table 4.5 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

Thresholds for single outage durations are 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 the table multiplied by the number of customers affected/34 000. Aurora must continue to make payments based on the unadjusted thresholds, with half the payments made to customers below the adjusted threshold recoverable through tariffs in the following year.[215]

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 rate 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.[216]

Total GSL payments are capped at two times the cumulative allowance in Table 4.6 below.

[215] OTTER, *Final Report*, Sep 2007, p. 235.
[216] ibid, p. 234.

Table 4.6 GSL allowance in the current regulatory control period

	June 2008	2008/09	2009/10	2010/11	2011/12
Allowance ($ million 2007)	0.924	1.740	1.603	1.475	1.344

Source: OTTER, Sep 2007, p.234

Table 4.7 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.

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 TEC. The charter must state the services and level of standard of such services that a customer in entitled to receive. Under the 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 4.8 below.

Table 4.8 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 Energy, *Tasmanian Electricity Customer Charter*, March 2010.

4.7 Proposed application of the STPIS to Aurora

4.7.1 S-factor component

4.7.1.1 Timing

Clause 2.4 of the STPIS provides that a DNSP must measure its performance in accordance with the STPIS from the first day to the last day of each regulatory year of the regulatory control period to which this scheme applies, or as otherwise determined by the AER. The AER's preliminary position is to require Aurora to measure its performance from the first day to the last day of each regulatory year in the forthcoming regulatory control period.

4.7.1.2 Revenue at risk

The cap on revenue at risk balances the risk of fluctuations in the prices of electricity against the benefit of the incentive to improve performance. Fluctuations in the cost of electricity can have negative consequences for both DNSPs and customers. The default cap of ± 5 per cent revenue at risk under the scheme restricts the volatility in electricity prices to an acceptable range.

The level of revenue at risk limits the incentive for DNSPs to provide service performance improvements. This is because, when a DNSP increases performance to a level where the cap has been reached, there is no further financial incentive to improve performance above that level. Conversely, when a DNSP underperforms against the target to the extent that it reaches the penalty cap, the financial incentive to prevent further decline in performance is mitigated.

The default level of revenue at risk is under the STPIS of ± 5 per cent significantly higher than the revenue at risk applied to Aurora in its 2003–07 determination. Under the previous Tasmanian scheme the revenue at risk was 1.25 per cent of Aurora's annual revenue.[217] As a result, the AER's STPIS will provide a less circumscribed incentive for Aurora to improve its service performance.

The AER does not propose to deviate from the default maximum ± 5 per cent revenue at risk in the Framework and Approach. Under the STPIS Aurora is able to propose a different level of revenue at risk if it can demonstrate that a different level of revenue at risk is consistent with the objectives of the scheme.

The AER seeks comment on the application of a ± 5 per cent level of revenue at risk under the s-factor to Aurora in the forthcoming regulatory control period.

4.7.1.3 STPIS applied within a control mechanism

The AER's preliminary position is that the s-factor will be incorporated into the control mechanism as outlined in chapter 3 of this paper.

[217] OTTER, *Final Report*, Sep 2003, p. 119.

4.7.1.4 Reliability of supply component

The STPIS allows for the potential inclusion of three parameters for reliability of supply: SAIDI, SAIFI and MAIFI. The AER's preliminary position is that the SAIDI and SAIFI parameters will apply to Aurora in the forthcoming regulatory control period. Separate performance targets will be calculated for different geographical regions in Aurora's network based upon supply reliability categories for supply reliability standards in the TEC.

Across jurisdictions there are different metrics used to measure network performance. The typical metrics used are SAIDI, SAIFI and MAIFI. Data collection and the method of calculating these performance measures differ from state to state. In the Tasmanian Energy Supply Industry Performance Report OTTER reports SAIDI and SAIFI performance for Aurora's network as a whole. This data has been reported since the 2002–03 financial year.[218] Performance data in the Tasmanian performance report is broken down into the geographical categories CBD, urban, rural short and rural long. These categories align with the default feeder categories in the STPIS.

Aurora has stated that it is unable to provide accurate MAIFI data. Estimates of whole feeder MAIFI are based on manual data extraction, and estimates of partial feeder MAIFI are impossible. Aurora contends that the introduction of a data collection and analysis system to provide MAIFI information would impose a major cost in infrastructure and resources.[219]

Aurora has advised that it does not have information on actual customer numbers connected to the distribution network and instead uses connected kVA as a proxy for customer numbers.[220] Instead Aurora collects network reliability data in accordance with the categorizations and metrics in the TEC supply reliability standards and OTTER's GSL scheme. These differ from the feeder categories, and SAIDI, SAIFI and MAIFI metrics used in the STPIS. The STPIS applies the feeder categories employed in the national regulatory reporting templates developed by the utility regulators forum (URF). The segmentation applied to Aurora's network for the purpose of the GSL scheme is as follow: Critical Infrastructure, High Density Commercial, Urban, High Density Rural and Low Density Rural.[221]

Aurora's electricity distribution network has grown around hydro generation in Tasmania. This dispersed generation has led to an uncommon network structure with long feeders often servicing urban areas. These long feeders mean that the categorization of network areas under the URF feeder definition may not be well suited to Aurora's network. Further, the joint working group between Aurora, OTTER and OEPC identified that the feeder classifications masked poor network performance and did not appropriately target supply reliability standards. As a result, OTTER decided to adopt a different classification approach for sections of Aurora's network

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218 OTTER, *Tasmanian Energy Supply Industry Performance Report 2008–09*, Dec 2009, p. 89.

219 Aurora, *Submission to Annual Distribution Network Service Providers, Annual Information Reporting Requirements Issues Paper*, October 2008, p. 8.

220 Aurora, *Information paper for AER: services, classifications and control mechanisms — Framework and approach process*, May 2010, p. 9 (Aurora, *Information paper*, May 2010).

221 OTTER, Guideline Guaranteed Service Level Scheme, December 2007, p. 6.

developed by the joint working group. This classification approach segmented Aurora's network in accordance with the load density around transformers. The network was segmented into 101 different communities in accordance with this classification.

Under OTTER's classification, actual customer numbers connected to the distribution network are not used. Instead connected kVA within transformers is used as an approximation for customer numbers. The methodology prescribed by OTTER also requires a kVA weighting when establishing reliability outcomes for the communities described in the Code.[222]

The AER considers that separate s-factor targets based on the network segmentation developed by OTTER for Aurora's network should be applied as these parameters have been developed specifically to apply to Aurora's network. At this stage, four years of historical data are available upon which to base these targets. Applying the STPIS network segmentation would also require Aurora to collect and report supply reliability data in two different forms; in accordance with the STPIS and the TEC supply reliability standards.

Clause 3.1(d) of the STPIS allows network areas to be segmented by methods other than the network types in the STPIS so long as the alternative method better meets the objectives of the STPIS. Adopting the existing network categories in Tasmania would better satisfy the requirements of the rules by better addressing the requirements under:

- clause 6.6.2(b)(3)(ii) taking into account the existing regulatory obligations or requirements to which Aurora is subject and adopting an approach that is in line with these objectives

- clause 6.6.2(b)(3)(iii) by aligning future performance targets with the past performance parameters of the distribution network

- Clause 6.6.2(b)(3)(vi) by ensuring that the targets are accurately set for different sections of the network reflecting the willingness to pay of customers within those network sections.

Under clause 2.6(c) of the STPIS, the AER will have regard to transitional issues when considering the appropriate targets upon which the service incentive scheme is to be based. The AER's preliminary position is to apply supply reliability targets based upon the existing Tasmanian network categorisation. The AER will set supply reliability targets using the existing network categories, but applying the SAIDI and SAIFI parameters to these categories. SAIDI and SAIFI targets will be calculated for each of these individual categorisations in accordance with reliability of supply data used to calculate GSL payments.

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[222] Aurora, *Information paper*, May 2010, p. 9.

The AER welcomes submissions on the application supply reliability targets based upon network segmentation under the Tasmanian Electricity Code.

4.7.1.5 Performance targets

The AER's preliminary position is to calculate performance targets for Aurora in accordance with the methodology provided in the STPIS. Clause 3.2.1 of the STPIS provides that performance targets must not deteriorate across regulatory years and must be based on average performance over the past five regulatory years. These performance targets are to be adjusted to ensure that average performance over the past five regulatory years reflects events excluded under the scheme. These performance targets are also to be adjusted to reflect any approved performance improvements.

4.7.1.6 Incentive rates

Incentive rates under the AER's STPIS are based on the VCR stated in the scheme. The VCR is used to calculate the incentive rate for the STPIS. For the CBD segment the VCR is $95 700/MWh (in September 2008 $).[223] For all other Parameters the VCR is $47 850/MWh (September 2008 $).[224] The AER's preliminary position is to ascribe the CBD VCR to critical infrastructure and high density segments of Aurora's network. The critical area and high density commercial segments of Aurora's network are analogous to the CBD classification under the STPIS. The standard VCR of $47 850 should apply to all other sections of the network as these would not considered standard network areas.

Aurora may elect to propose an alternative incentive rates to those stated in the STPIS. Should Aurora elect to do this it should provide the AER with the methodology used to calculate the value and research supporting the calculation.

4.7.1.7 Exclusions

The exclusions proposed under clause 3.3 of the STPIS will apply to Aurora. Under clause 3.3, the following may be excluded when calculating the revenue increment or decrement under the scheme:

1. load shedding due to a generation shortfall.
2. automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition.
3. load shedding at the direction of the Australian Energy Market Operator (AEMO) or a system operator.
4. load interruptions caused by a failure of the shared transmission network.
5. load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning.

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223 AER, STPIS clause 3.3.2(b)(1)
224 AER, STPIS clause 3.3.2(b)(2)

6. load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.
7. All events that occur on a major event day (MED)where daily unplanned SAIDI for the DNSP's distribution network exceeds the major event day boundary, as set out in appendix D of the STPIS.

4.7.1.8 Major event day boundary

To accurately calculate the MED threshold, daily data detailing the minutes-off-supply for Aurora's entire network. In calculating the performance targets for Aurora the AER also requires daily data to exclude the effects of MED days from the target. The AER will have regard to the data that is available from Aurora when calculating the appropriate MED threshold and reliability targets.

Aurora has confirmed that it collects network reliability on a daily basis.[225] Aurora considers that may be possible to calculate the MED boundary under the AER's definition, however, they would need to undertake further work to confirm this.[226]

The threshold for GSL payments for single supply interruption events changes depending on the number of people affected by these events. When the number of people affected by the event exceeds 34 000 then the threshold will change relative to the number of people affected above the 34 000 threshold.[227] 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. This mechanism effectively limits the risk that Aurora faces from major network outages.

The AER could apply a MED threshold that acts concurrently with the existing TEC GSL scheme target adjustment threshold by excluding events that affect more than 34 000 customers. This would not be appropriate however, as the GSL duration of interruption threshold has a significantly different objective to the AER MED threshold. The GSL threshold only applies to an individual outage event, whereas the AER MED threshold applies to all the s-factor events on a particular day. Further, whereas all s-factor events that occur on a MED day under the STPIS are excluded from the financial effects of the scheme, under the TEC GSL threshold only the events that require payment below the threshold qualify for a financial exemption. Aurora must still finance half of the payments, with the other half being subsidised by customers through tariffs in the next year.

The AER's preliminary position is to apply the default STPIS MED threshold of 2.5 beta to Tasmania in the forthcoming regulatory control period. The STPIS MED threshold is calculated annually based upon the most recent five years of audited daily network reliability data. As such, the STPIS MED threshold would reflect the recent operating conditions of Aurora's network. Under OTTER's previous s-factor scheme,

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[225] Aurora, *Information paper*, May 2010, p. 10.
[226] ibid.
[227] OTTER, *Final Report*, Sep 2007, p. 235.

a MED exemption threshold of 6.06 SAIDI was applied.[228] The AER's MED threshold would act in a similar fashion to this previous threshold.

Aurora has scope under the STPIS to propose a higher MED threshold if it can be demonstrated that the higher threshold consistent with the goals of the scheme. Additionally, under clause 2.2 of the STPIS, a DNSP may make a proposal to vary the application of the STPIS. The DNSP is required to demonstrate how the proposed variation is consistent with the objectives of the STPIS.

> The AER is seeking comments on:
>
> - the application of the s-factor supply reliability parameters to Aurora in the forthcoming regulatory control period
> - the appropriateness of applying reliability of supply component of the STPIS to Aurora's network categorisations under the TEC
> - the availability and robustness of data to be used calculate the MED threshold and performance targets for Aurora.

4.7.2 Quality of supply component

There is currently no quality of supply measures under the STPIS.

4.7.3 Customer service component

4.7.3.1 Parameters

The AER's preliminary position is to apply the telephone answering parameter in the customer service component of the STPIS to Aurora. The STPIS contains the following customer service parameters:

- telephone answering
- streetlight repair
- new connections
- response to written enquiries.

The STPIS states that the telephone answering parameter will apply during a regulatory control period, except where the AER determines otherwise in its distribution determination. In accordance with clause 5.1(d) of the scheme, the AER may require a DNSP to apply any or all of the parameters specified above. Clause 5.1(e) of the STPIS provides that the AER will only require a DNSP to apply a customer service parameter where the AER has classified that parameter as a standard control distribution service.

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[228] OTTER, *Draft Position Paper Service Incentive Scheme*, May 2007, p. 36.

Aurora collects customer service data for call centre performance, streetlight repair and new connections. Aurora does not collect data on responses to written enquiries in a manner that would support the current STPIS.[229] The definition of the call answering parameter under the STPIS differs from the definition upon which Aurora currently reports to OTTER. Under clause 5.3.1 (d) of the STPIS, if reliable data does not exit, the scheme allows targets to be based upon an alternative methodology or a benchmark.

At this stage, as it is not proposed that street lighting services be classified as a standard control distribution services, the AER is not likely to apply the streetlight repair customer service parameter. Further, the AER notes that there is already an incentive for Aurora to repair streetlights within a given timeframe under Aurora’s Tasmanian Electricity Customer Charter.[230]

Streetlight repair and response to written enquiries are currently monitored by OTTER, though no penalty payments are required for poor performance. Streetlight repair, new connections and response to written enquiries have not been applied by the AER in other jurisdictions. Aurora, in its regulatory proposal may propose to apply other customer service parameters under the STPIS.

4.7.3.2 Revenue at risk

The AER’s preliminary position is apply the default revenue at risk for the customer service component of the STPIS. Clause 5.2(a) of the STPIS provides that the maximum increment or decrement for all customer service parameters in aggregate for each regulatory year shall be 1 per cent. The maximum revenue at risk for any individual customer service parameter under the STPIS is ± 0.5 per cent of revenue. As the AER’s preliminary position is only to apply the call answering parameter, the maximum revenue at risk for the customer service component of the s-factor will be ± 0.5 per cent of revenue. Under clause 5.2(b) of the STPIS the maximum revenue at risk for customer service component is ± 0.5 per cent of revenue.

4.7.3.3 Performance targets

Clause 5.3.1(a) of the STPIS provides that performance targets for each customer service parameter are to be based on average performance over the previous five years. The AER’s preliminary position is to calculate the telephone answering performance target based upon average performance over the previous five years.

4.7.3.4 Incentive rate

The incentive rate for the telephone answering parameter under the STPIS is −0.04 per cent per unit of the telephone answering parameter. The AER’s preliminary position is to apply the standard incentive rate for the telephone answering parameter. Should Aurora propose to apply further customer service parameters, the incentive rate for these parameters will be based upon the value that customer attribute to the level of service proposed. Incentive rates will be calculated at the commencement of

[229] Aurora, *Information paper*, May 2010, p. 10.
[230] Aurora, *Customer Service Charter*, March 2010, p. 4.

the regulatory control period (in the distribution determination) and will apply for the duration of the regulatory control period.

4.7.3.5 Exclusions

Clause 5.4(a) of the STPIS provides that:

> Where the impact of an event is to be excluded from the calculation of a revenue increment or decrement under the 'reliability of supply' component as provided for in clause 3.3, the impact of that event may be excluded from the calculation of a revenue increment or decrement for the 'telephone answering' parameter as appropriate.

If Aurora proposes other customer service parameters in its regulatory proposal it may also propose appropriate exclusions for these parameters.

> The AER seeks comment on the application of the telephone answering customer service parameter to Aurora in the forthcoming regulatory control period.

4.7.4 Guaranteed service level component

The STPIS states that where jurisdictional electricity legislation imposes an obligation on a DNSP to operate a GSL scheme the AER's GSL scheme will not apply. Clause 8.5 of the TEC provides that Aurora must comply with any guideline, issued by the regulator, which sets out the minimum level of network reliability performance to be provided to a customer by a DNSP.

OTTER published the current version of the Tasmanian GSL scheme in December 2007. The Tasmanian GSL scheme does not have a sunset clause, however can be repealed by OTTER. At this stage OTTER has not indicated that it will repeal the existing GSL scheme. Given that OTTER has not indicated that it will repeal the GSL scheme under the TEC, the AER anticipates that the STPIS GSL scheme will not apply to Aurora in the forthcoming regulatory control period.

Further, clause 8.3.1 of the TEC provides that Aurora must publish a customer service charter, approved by the regulator, stating the services and the level and standard of such services that a customer is entitles to receive from Aurora. Aurora's customer service charter includes a pledge to make payments should Aurora fail to provide the minimum level of service stated in the charter. This customer charter effectively applies a further GSL obligation on Aurora. At this stage it is the AER's understanding that the TEC will not be amended to remove the requirements of the customer service charter.

4.8 Consideration of NER criteria

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.

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.[231] 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.

NER criteria 6.6.2(b)(3)(ii) any regulatory obligation or requirement to which Aurora is subject

The AER's preliminary position is 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.

The AER has had regard to the regulatory obligations to which Aurora is subject. The AER proposes to apply s-factor supply reliability targets that align with the current TEC supply reliability standards, supply reliability categories. This will 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.

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.

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231 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.

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 the Aurora as part of the distribution determination are the efficiency benefit sharing scheme (EBSS) and the demand management incentive scheme (DMIS).

The STPIS works as a 'counterbalance' to the EBSS, which 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.

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 on in practice.

As discussed above, in the previous regulatory control period OTTER did not apply a s-factor incentive scheme in Aurora's current regulatory control period as it was deemed that there was inherent uncertainty in forecasting an appropriate s-factor targets. Instead OTTER decided to publically report on Aurora's service performance. Though public reporting does 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. The AER grants DNSPs a revenue allowance to maintain quality, reliability and security of supply of their networks. In the short run, some factors are outside of the control of the DNSPs. In the long run DNSPs have greater control of the variables that affect the reliability of their networks and can investment to maintain and improve the reliability of their network.

Once a distribution determination has been made, a DNSPs revenue allowance is locked-in for duration of the regulatory control period. In absence of the 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.

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.

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.

4.9 Consultation requirements under the NER

In developing and implementing a STPIS, the AER must consult with the authorities responsible for the administration of relevant jurisdictional electricity legislation. This paper provides an opportunity for stakeholders to provide submissions on the AER's preliminary positions on the application of the STPIS to Aurora. This paper will be provided to all authorities responsible for the administrations of relevant Tasmanian electricity legislation. The AER welcomes submissions from all stakeholders.

4.10 AER's preliminary position on the application of the STPIS to Aurora

The AER's preliminary position is to apply the supply reliability and customer service components of the STPIS to Aurora. The AER will not apply the STPIS GSL scheme as there is currently an existing GSL scheme in Tasmania.

The AER will apply the SAIDI and SAIFI reliability performance components of the STPIS. Separate SAIDI and SAIFI targets will be set for network segments in accordance with the existing network segments under the TEC minimum supply reliability standards. Targets will 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 will be the same as for CBD network sections under the STPIS. All other sections will 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 will calculate a MED boundary based upon the 2.5 beta method as specified in the STPIS.

For the customer service component the AER proposes to apply the telephone answering customer service parameter. The default level of revenue at risk of ± 0.5 per cent is proposed to be applied to the call answering parameter.

In forming this position, the AER has had regard to the factors in clause 6.6.2(b)(3) of the NER, and considers that:

- The use of VCR to determine incentive rates and weighting for parameters under the s-factor scheme reflects the willingness of customers to pay for improved performance in the delivery of services by the Victorian DNSPs. The use of VCR in setting incentive rates and weightings also means that any potential benefits to consumers under the STPIS are sufficient to warrant any reward or penalty under the scheme for Aurora.

- The STPIS will operate concurrently with the TEC minimum service standards to which Aurora is required to comply.

- Whilst Aurora will be penalised for diminished performance, it will also have the opportunity to gain financially for performance that exceeds the performance targets. Any incentive to reduce costs at the expense of service levels is counterbalanced by the corresponding penalties under the STPIS.

- The STPIS accounts for the past performance of Aurora's distribution network by setting s-factor targets based on Aurora's average performance over the previous five years, and

- The STPIS is designed to operate in conjunction with both the DMIS and EBSS. The STPIS balances the potential for the EBSS to provide incentives to inefficiently reduce operating expenditure at the risk of service levels and, in respect of the DMIS, is essentially neutral regarding the level of reliability of network and non network solutions, neither encouraging nor discouraging non-network alternatives to augmentation.

The AER welcomes submissions on this preliminary position on the application of the STPIS to Aurora in the forthcoming regulatory control period.

5 Application of efficiency benefit sharing scheme

5.1 Introduction

As part of its distribution determination, the AER's 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.[232]

This chapter sets out the AER's preliminary position on its 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 operating expenditure for a regulatory control period.[233]

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 Requirements of the NER

Clauses 6.3.2(a)(3) and 6.12.1(9) of the NER requires 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's distribution EBSS

The AER is required to develop and publish a scheme or schemes that provide for a fair sharing between DNSPs and users, where:

- the efficiency gains derived from the operating expenditure of DNSPs for a regulatory control period are less than; or
- the efficiency losses derived from the operating expenditure of DNSPs for a regulatory control period are more than;

[232] NER, cl. 6.3.2(a)(3) and constituent decision cl. 6.12.1(9)
[233] NER, cl. 6.5.8(a)

the forecast benchmark operating expenditure accepted or substituted by the AER for that regulatory control period.[234]

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, and
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.[235]

The AER's distribution EBSS was developed, and will be applied to Aurora, having regard to these factors.

The AER's preliminary position on the application of the EBSS to Aurora in the forthcoming regulatory control period is set out in the sections below.

5.3 Application of EBSS to Aurora

The AER has developed an EBSS in accordance with the requirements of the NER, which will be applied to Aurora in the forthcoming regulatory control period. In applying the EBSS to Aurora, the AER has had regard to the factors in clause 6.5.8(c) of the NER.

5.3.1 Previous application of EBSS by OTTER

Aurora is not currently subject to an EBSS.

OTTER applied an EBSS to Aurora's operating expenditure for the 2003 regulatory control period.[236] Similar to the AER's EBSS, OTTER's EBSS had a five year

[234] NER, cl. 6.5.8(a).
[235] NER, cl. 6.5.8(c).

carryover period. However, Aurora's expenditure during the 2003 regulatory control period was significantly higher than forecast. A strict application of the EBSS would have resulted in a negative carryover of $36.34m[237] into the 2007 regulatory control period. Therefore, in its 2007 decision OTTER elected to set the carryover amount for that period to zero, noting that:

- Clause 6.5.2 of the 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

- OTTER's 2003 decision provided no guidance as to the treatment of any negative efficiency carryovers, and

- 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.[238]

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',[239] it was concerned about an incentive scheme that is dependent on forecasts made many years in advance. 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 distributor to make efficiency gains in the next regulatory control period.[240]

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 distributor.[241] 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 distributor to earn a commercial rate of return.[242]

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.[243]

236 OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania—Final Report and Proposed Maximum Prices*, September 2007, p. 221.
237 ibid., p. 222.
238 ibid., p. 91.
239 ibid., p. 224.
240 ibid., p. 223.
241 ibid., p. 223.
242 ibid., p. 223.
243 ibid., p. 224.

5.3.2 Consideration of the NER factors

As noted above, the AER must have regard to a number of factors in implementing the EBSS. These factors are discussed in turn below. Recognition of these factors in the development of the EBSS itself is discussed in more detail in the AER's final decision for its EBSS, which is available on the AER's website at http://www.aer.gov.au.

5.3.2.1 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.[244] 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 this way, Aurora will retain 30 per cent of the total benefits of the efficiency gain, 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.

5.3.2.2 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

[244] AER, *Final decision efficiency benefit sharing scheme*, June 2008, pp. 17–18.

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.

This 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.[245] The AER does not propose to extend the EBSS to Aurora's capital expenditure.

5.3.2.3 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.

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

[245] ibid., p. 6.

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.[246]

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.

5.3.2.4 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 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.

5.3.2.5 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.

[246] ibid., p. 5.

5.3.3 AER's preliminary position on the application of an EBSS to Aurora

The AER's preliminary position is that the EBSS will be applied to Aurora in the forthcoming regulatory control period. 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.[247] Because the EBSS is symmetrical, any efficiency losses would also be shared between customer and Aurora, so that the potential for financial penalty is balanced.[248] 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 for the length of the carryover period, regardless of the year in which the gain or loss is realised.[249]

- 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.[250]

- 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.[251]

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

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247 NER, cl. 6.5.8(c)(1).
248 NER, cl. 6.5.8(c)(3).
249 NER, cl. 6.5.8(c)(2).
250 NER, cl. 6.5.8(c)(4).
251 NER, cl. 6.5.8(c)(5).

information on Aurora's historical expenditure will assist the AER to make reasonable and accurate forecasts for the purpose of the EBSS.

- The AER currently applies an EBSS mechanism to DNSPs in all other regulated state and territory jurisdictions. For this reason, it is preferable in the interests of consistency to apply an EBSS to Aurora in the Tasmanian jurisdiction.

The EBSS allows Aurora to propose 'uncontrollable' cost categories for exclusion from the scheme.[252] 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.

[252] AER, *Final decision*, June 2008, p. 6.

6 Application of demand management incentive scheme

6.1 Introduction

Demand management broadly refers to the implementation of strategies to address growth in demand or peak demand, with a view to deferring or removing the need to augment the network (to relieve network constraints). Network providers 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. 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.

This chapter sets out the AER's likely approach to the application of a DMIS to Aurora for the forthcoming 2012–2017 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.[253] The DMIS operates in conjunction with existing incentives in the regulatory framework to pursue these objectives.

6.2 Requirements of the NER

The AER, in its distribution determination for Aurora, must specify how a DMIS (if any) will be applied to it in the forthcoming regulatory control period.[254]

The AER can develop and publish incentive schemes 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.[255]

Consultation on a DMIS suitable for consistent application across the NEM has not yet commenced. Therefore, the AER will consult separately on the development of a DMIS that can be applied to Aurora in the forthcoming regulatory control period. This consultation will occur concurrently with the consultation on this preliminary positions paper. This preliminary positions paper sets out the AER's likely approach to the application of the proposed DMIS to Aurora. The AER's proposed DMIS for Aurora and its explanatory statement are available on the AER's website, www.aer.gov.au.

When the AER publishes its final framework and approach paper for Aurora, the Tasmanian DMIS will be finalised. The AER will take into account submissions on both this paper and the proposed DMIS and will set out its proposed approach to the

253 NER, cl. 6.6.3(a).
254 NER, cl. 6.3.2.
255 NER, cl. 6.6.3(a).

application of the Tasmanian DMIS in it’s final framework and approach paper to be published in November 2010.

6.3 Demand management incentive schemes under chapter 6 of the NER

In developing and implementing a DMIS, the AER must have regard to the factors in clause 6.6.3(b) of the NER, being:

- 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 effect of a particular control mechanism (for example, price—as distinct from revenue — regulation) on a DNSP’s incentives to adopt or implement efficient non-network alternatives
- the extent the DNSP is able to offer efficient pricing structures
- the possible interaction between a DMIS and other incentive schemes, and
- the willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme.[256]

The distribution consultation procedures in clause 6.16 of the NER require the AER to publish a proposed DMIS and explanatory statement, invite submissions and give stakeholders and interested parties at least 30 business days to respond. Within 80 business days of publishing the proposed DMIS, the AER must publish its final decision and DMIS.

6.4 Structure of the proposed DMIS

The AER’s proposed DMIS that will apply to Aurora consists of a demand management innovation allowance (DMIA). The DMIS allows for recovery of costs for demand management projects and programs undertaken throughout the regulatory control period, subject to satisfaction of defined criteria. The DMIA is provided as a capped, annual *ex ante* allowance, and subject to a single adjustment in the subsequent regulatory control period to return any expenditure not approved, or any amount of the DMIA that is not spent, to customers.

Annual reporting requirements create transparency in the operation of the DMIA, and allow the AER, DNSPs, users and other stakeholders to monitor the effectiveness and outcomes of the scheme.

[256] The AER has had regard to these considerations when developing the proposed DMIS in the documents it has prepared for consultation and in section 6.5 of this document, below.

6.5 Application of the AER's DMIS to Aurora

In applying a DMIS to Aurora the AER must have regard to the factors in clause 6.6.3 of the NER which are discussed 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 and 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. It is for this reason that 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, will have minimal cost impact on Tasmanian customers.

The AER's proposed 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, 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 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 preliminary position is to apply a revenue cap to Aurora. Under a revenue cap, revenue is not dependant on the DNSPs 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. Further, 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 they 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 the Victorian DNSPs the AER must have regard to the interaction of that scheme with other incentive schemes. As outlined above, the AER's preliminary position is that both an EBSS and STPIS will be applied to the Aurora DNSPs in the next 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 incentive 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. 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 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.

6.6 AER’s likely approach to the application of a DMIS

Having had regard to the requirements of the NER, the AER’s preliminary position is to apply a DMIS to Aurora in the forthcoming regulatory control period that comprises of a DMIA.

In determining the appropriate amount of the DMIA for Aurora, the AER has had regard to the relative size 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 and Queensland DNSPs, and for the 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 these allowances 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.

The DMIS complements the incentive properties that are expected to flow from the application of the STPIS and EBSS within the broader incentive framework set out in chapter 6 of the NER. The AER is satisfied that the combination of the capped DMIA will provide appropriate incentives to Aurora to adopt or implement efficient non-network alternatives under a weighted average price cap. The AER also considers that the scheme will not provide a reward that outweighs the benefits to consumers likely to result from the scheme or the willingness of customers and end users to pay for its implementation.

The AER seeks comment on its preliminary position to apply a DMIS to Aurora.

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

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
			Above standard metering services
Public lighting services	Unregulated	Alternative control services	Repair, replacement and maintenance of public lighting
			Alteration and relocation of existing public lighting assets
			Provision of new public lighting assets
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
Non-standard services	Unregulated	Unregulated	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

Source: AER analysis.

Defined terms

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