Preliminary positions

Framework and approach paper

ETSA Utilities 2010-15

June 2008

AUSTRALIAN
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Contents

Request for submissions

Issues regarding the AER's preliminary positions can be addressed in written submissions to the AER by Monday 11 August 2008.

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

Alternatively, submissions can be sent to:

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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.

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

Overview

The Australian Energy Regulator (AER) will assume responsibility for the economic regulation of ETSA Utilities, the distribution network service provider (DNSP) for South Australia, on 1 July 2010, with the commencement of its first distribution determination for that business.

Under chapter 6 of the NER, the AER must classify the distribution services to be provided by, and make a distribution determination for, ETSA Utilities for the forthcoming 2010-15 regulatory control period. In anticipation of its distribution determination, the AER is required to prepare and publish a framework and approach paper by November 2008. The framework and approach paper assists ETSA Utilities in preparing its regulatory proposal to the AER by setting out the AER's likely approach to the classification of services provided by ETSA Utilities and stating the forms of control that will apply to each class of services. The framework and approach paper also sets out the AER's likely approach to the application of the Service Target Performance Incentive Scheme, Efficiency Benefit Sharing Scheme and Demand Management Incentive Scheme to ETSA Utilities.

This paper is the first step in the AER's consultation on its framework and approach paper for ETSA Utilities, which needs to be finalised by November 2008. Submissions are sought on the following preliminary positions:

- the classification of prescribed distribution services provided by ETSA Utilities in the current regulatory control period as standard control services, and current excluded services as negotiated distribution services
- the application of a modified revenue yield control to standard control services
- the application, to standard control services, of –

  - a service target performance incentive scheme in the form of an s-factor adjustment for both reliability of supply and customer service performance
  - the AER's efficiency benefit sharing scheme
  - a demand management incentive scheme in the form of an annual demand management innovation allowance

The AER also seeks submissions on the appropriate transitional arrangements to take into account the change from the pre-tax revenue model currently applied to ETSA Utilities to the post tax model required by the NER.

Summary

ETSA Utilities is the Distribution Network Service Provider (DNSP) for South Australia. It is currently regulated by the Essential Services Commission of South Australia (ESCOSA), in accordance with the Electricity Distribution Price Determination (EDPD) for the regulatory control period 1 July 2005 to 30 June 2010.

The Australian Energy Regulator (AER) will assume responsibility for the economic regulation of ETSA Utilities on 1 July 2010, with the commencement of its first distribution determination for that business. However, the process that the AER must follow in making that distribution determination will take place over the final two years of the current regulatory period, commencing on 30 June 2008 with the release of this (preliminary positions) paper. During that time, ESCOSA will remain responsible for administration of the 2005-10 EDPD.

The AER's functions and powers are set out in the National Electricity Law (NEL) and the National Electricity Rules (NER). Under chapter 6 of the NER, the AER may classify distribution services to be provided by a Distribution Network Service Provider (DNSP), and make distribution determinations for each DNSP.

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 the DNSP in preparing its regulatory proposal to the AER by:

- 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
- 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 to the DNSP of a service target performance incentive scheme or schemes
  3. the application to the DNSP of an efficiency benefit sharing scheme or schemes
  4. the application to the DNSP of a demand management incentive scheme or schemes
  5. any other matters on which the AER thinks fit to give an indication of its likely approach.

The control mechanisms applied by 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 a DNSP, however:

- the classification of services in the distribution determination must be as set out in the framework and approach paper unless the AER considers that, in light of the 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 appropriate and necessary to satisfy the requirements of the NEL and NER.

This document sets out the AER's preliminary positions on the matters to be addressed in its framework and approach paper for ETSA Utilities' 2010-15 regulatory control period. The AER's framework and approach paper will be finalised by November 2008 following consideration of submissions to this paper.

Each of these is summarised in the sections below, and discussed in detail in the chapters that follow.

Classification of services

The NER requires the AER to act on the basis that:

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

unless a different classification is clearly more appropriate.

The AER's preliminary position is that, with one exception, the service classifications for ETSA Utilities' regulated distribution services in the current 2005-2010 regulatory control period are consistent with the requirements of cll. 6.2.1 and 6.2.2 of the NER, and that no alternative classification is clearly more appropriate at this time. On this basis:

- ETSA Utilities' prescribed distribution services are likely to be classified as direct control services, and further classified as standard control services.
- Excluded services provided by ETSA Utilities will be classified as negotiated distribution services under the NER.

However, pole and duct rental for telecommunications purposes, which are currently classified as excluded services, do not fall within the NER definition of distribution services. These services are therefore outside the scope of the economic regulatory framework for distribution services in chapter 6 of the NER, and the AER's distribution determination for ETSA Utilities.

Control mechanisms

The AER's preliminary position is that, subject to minor adjustments to address issues identified in the course of its preliminary assessment, the form of control applied by ESCOSA to prescribed services in the current regulatory period is available under the NER for standard control services in the forthcoming period.

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

Upon preliminary assessment, the AER considers that the current control mechanism meets the requirements of the NER in relation to control mechanisms. While potential issues have been identified with this control mechanism in terms of incentives and the allocation of risk, the AER considers that these can be addressed through adjustment mechanisms the same as, or similar to, those already in place.

The AER's preliminary position is that none of the distribution services currently provided by ETSA Utilities can be appropriately classified as alternative control services for the 2010-2015 regulatory control period. On this basis, the AER does not consider it necessary to offer preliminary positions on what form of control may apply to such services in these circumstances.

Application of service target performance incentive scheme

The AER's distribution STPIS was released on 26 June 2008. The AER's preliminary position is that it is likely to apply the reliability of supply and customer service components of the AER's STPIS to ETSA Utilities in the forthcoming regulatory control period.

Targets for the reliability of supply component will be attached to SAIDI and SAIFI, with separate targets for each segment of the network, in accordance with the SCONRRR feeder categories identified in the STPIS. Targets will reflect available data on historical performance, with adjustments as necessary under the STPIS. The AER does not consider the sampling method currently utilised in ETSA Utilities' reporting of MAIFI is a suitable basis of performance measurement for a financial incentive such as the STPIS, and will not include MAIFI as a parameter for ETSA Utilities at this time.

There will be no quality of supply component for the forthcoming regulatory control period. However, the AER will monitor ETSA Utilities' quality of supply performance as reported to ESCOSA, and will explore the desirability of including quality of supply parameters in its STPIS in future regulatory control periods.

For the customer service component, the AER proposes that the telephone answering parameter (as defined in appendix A of the STPIS) will apply to ETSA Utilities for the forthcoming regulatory control period. Other parameters under this component may be proposed by ETSA Utilities in its regulatory proposal.

The AER will not apply the GSL component of the STPIS to ETSA Utilities in the forthcoming regulatory control period as ETSA Utilities is already subject to a jurisdictional GSL scheme.

In the forthcoming regulatory control period, the AER's STPIS will operate concurrently with average service standards and GSLs set and administered by ESCOSA. In forming this preliminary position, the AER has had regard to ESCOSA's current consultation on the jurisdictional service standards to apply to ETSA Utilities for the 2010-15 regulatory control period, a draft decision on which was released on 6 June 2008. ESCOSA's final decision, which is expected to be released in August 2008, will be taken into account in the AER's framework and approach paper when it is released in November 2008.

Application of efficiency benefit sharing scheme

The AER's distribution EBSS was released on 26 June 2008. The AER's preliminary position is that the AER's EBSS will be applied to ETSA Utilities in the forthcoming regulatory control period.

The jurisdictional derogation for South Australia in chapter 9 of the NER provides that the EBSS applied by the AER under its distribution determination for ETSA Utilities for the forthcoming regulatory control period must be consistent with the statement of regulatory intent (SORI) issued by ESCOSA in March 2007.

The SORI does not limit the AER's discretion in the development or implementation of its own EBSS, but requires the AER to apply carryovers under the existing efficiency carryover scheme to ETSA Utilities, as intended by ESCOSA in its current regulatory period. That is, that any relevant efficiency gains, negative or positive, from the current scheme administered by ESCOSA should be included for the purposes of calculating forecast opex and capex at the outset of the forthcoming regulatory control period.

For efficiency gains realised in the current regulatory period, each annual carryover amount for the current regulatory period will be calculated and used in the building block determination for the forthcoming regulatory control period. The AER will incorporate all negative and positive carryover amounts accrued in any year of the current regulatory period into forecast opex amounts for the forthcoming regulatory control period. Although the AER does not include capex in its EBSS, capex efficiency carryovers that have been realised in the current regulatory period will be included in the capex forecasts for ETSA Utilities in the forthcoming regulatory control period.

Application of demand management incentive scheme

Consultation on a national DMIS suitable for consistent application across the NEM has not yet commenced. A national DMIS will not be sufficiently developed in time for the AER to prepare and consult on a likely approach to its application to ETSA Utilities before it must publish its framework and approach paper by 30 November 2008. For that reason, the AER has consulted separately on the development of a DMIS that can be applied to ETSA Utilities, and to Energex and Ergon Energy, whose framework and approach papers are to be completed at the same time (SA-Qld DMIS). A proposed SA-Qld DMIS was published on 30 June 2008.

This paper sets out the AER's preliminary position on the application of the proposed SA-Qld DMIS to ETSA Utilities. In its framework and approach paper, the AER will take into account submissions on both this paper and the proposed SA-Qld DMIS in setting out its likely approach to the application of the final SA-Qld DMIS to ETSA Utilities.

The AER proposes to apply a DMIS in the form of a demand management innovation allowance to ETSA Utilities for the 2010-15 regulatory control period.

The AER's preliminary position is that the amount of the allowance will be capped at $600 000 per annum, or a total of $3 million over the regulatory control period. The

AER considers that this allowance will allow ETSA Utilities to carry out a number of small-scale demand management projects, or a single larger-scale demand management project, per year of the regulatory control period.

The AER considers it appropriate that the primary source of funding for demand management in the forthcoming regulatory control period should be the forecast opex and capex allowances approved in the distribution determination. The demand management innovation allowance operates as a complement to this allowance, and will be provided in addition to any opex and capex allowances for demand management projects included within the AER's distribution determination for ETSA Utilities.

Other matters

Transition from pre-tax to post-tax revenue model

The jurisdictional derogation for South Australia in chapter 9, Part D of the NER requires that the AER's distribution determination for ETSA Utilities for the regulatory control period commencing on 1 July 2010 must incorporate appropriate transitional arrangements to take into account the change from a pre-tax to a post-tax revenue model.

Chapter 7 of this paper sets out the AER's preliminary position on the approach to the transition of ETSA Utilities from a pre-tax to post-tax revenue model. The AER considers it appropriate to give an indication of the AER's likely approach to the transition from a pre-tax to a post-tax revenue model at this time, to enable interested stakeholders to provide views on how such a transition should be made.

On completion of the framework and approach process, it is expected that information requirements relating to the application of a post-tax approach will be included as a part of a Regulatory Information Notice detailing the information that ETSA Utilities must provide in its regulatory proposal to the AER on 31 May 2009. This approach is similar to the approach taken in the NSW/ACT transition process.

Consultation process

The framework and approach paper must be prepared in consultation with the relevant DNSP and with other interested stakeholders.

The AER must commence consultation on its framework and approach paper for ETSA Utilities on 30 June 2008, and must complete and publish the framework and approach paper by 30 November 2008.

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	**30 June 2008**
Submissions on preliminary positions close	11 August 2008
Public forum	*September 2008**
Publication of final framework and approach paper	**30 November 2008**

* Subject to sufficient interest from stakeholders

1 Introduction

The Australian Energy Regulator (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 National Electricity Law (NEL) and the National Electricity Rules (NER).

Under chapter 6 of the NER, the AER may classify distribution services to be provided by a Distribution Network Service Provider (DNSP), and must make distribution determinations for each DNSP.

ETSA Utilities is the DNSP for South Australia. Its provision of distribution services is currently regulated by the Essential Services Commission of South Australia (ESCOSA), in accordance with the Electricity Distribution Price Determination (EDPD) for the regulatory control period 1 July 2005 to 30 June 2010.

The AER will assume responsibility for the economic regulation of ETSA Utilities on 1 July 2010, with the commencement of its first distribution determination for that business. However, the process that the AER must follow in making that distribution determination will take place over the final two years of the current regulatory period, commencing on 30 June 2008. During that time, ESCOSA will remain responsible for administration of the 2005-10 EDPD.

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 is summarised in table 1.1 below. This preliminary positions paper is the first step in the AER's preparation of and consultation on its framework and approach paper for ETSA Utilities.

Table 1.1 Procedures for making a distribution determination

1	**AER's framework and approach paper***	
	AER to commence preparation of and consultation on framework and approach paper for ETSA Utilities	30 June 2008
	AER to publish framework and approach paper for ETSA Utilities	30 November 2008
2	**Regulatory proposal and distribution determination**	
	ETSA Utilities to submit regulatory proposal to the AER	31 May 2009
	AER to publish draft decision on distribution determination for ETSA Utilities	*30 November 2009***
	AER to publish final decision and distribution determination for ETSA Utilities	30 April 2010
	ETSA Utilities to submit initial pricing proposal for approval	May 2010
	AER to publish approved pricing proposal	June 2010
	Distribution determination and approved pricing proposal to commence	1 July 2010

* Note that the timelines for preparation of, and consultation on, the framework and approach paper for ETSA Utilities differs in part from the equivalent consultation for Energex and Ergon Energy. By operation of the transitional provisions for Queensland, the AER's consultation on the classification of services provided by Energex and Ergon Energy, and the forms of control that will apply to those businesses, commenced on 31 March 2008 with the submission of proposals from those businesses, and must be completed by 31 August 2008. Consultation on the AER's likely approach to the application of schemes is the same for all three DNSPs.

** The NER do not specify a date by which the AER must publish a draft decision on its distribution determination for ETSA Utilities. This date is indicative only.

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 the DNSP in preparing its regulatory proposal to the AER by:

- 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
- 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 to the DNSP of a service target performance incentive scheme or schemes

3. the application to the DNSP of an efficiency benefit sharing scheme or schemes

4. the application to the DNSP of a demand management incentive scheme or schemes

5. any other matters on which the AER thinks fit to give an indication of its likely approach.

The control mechanisms applied by 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 a DNSP, however:

- the classification of services in the distribution determination must be as set out in the framework and approach paper unless the AER considers that, in light of the 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 appropriate and necessary to satisfy the requirements of the NEL and NER.

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 relationship 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 the DNSP, 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:

   i. classify a distribution service as a direct control service, or

   ii. classify a distribution service as a negotiated distribution service.

   If the AER decides against classifying a distribution service, the service is not regulated under the NER.[2]

2. The AER must classify direct control services (in level 1 above) as either:

[2] NER, cl. 6.2.1(a)

i. a standard control service, or

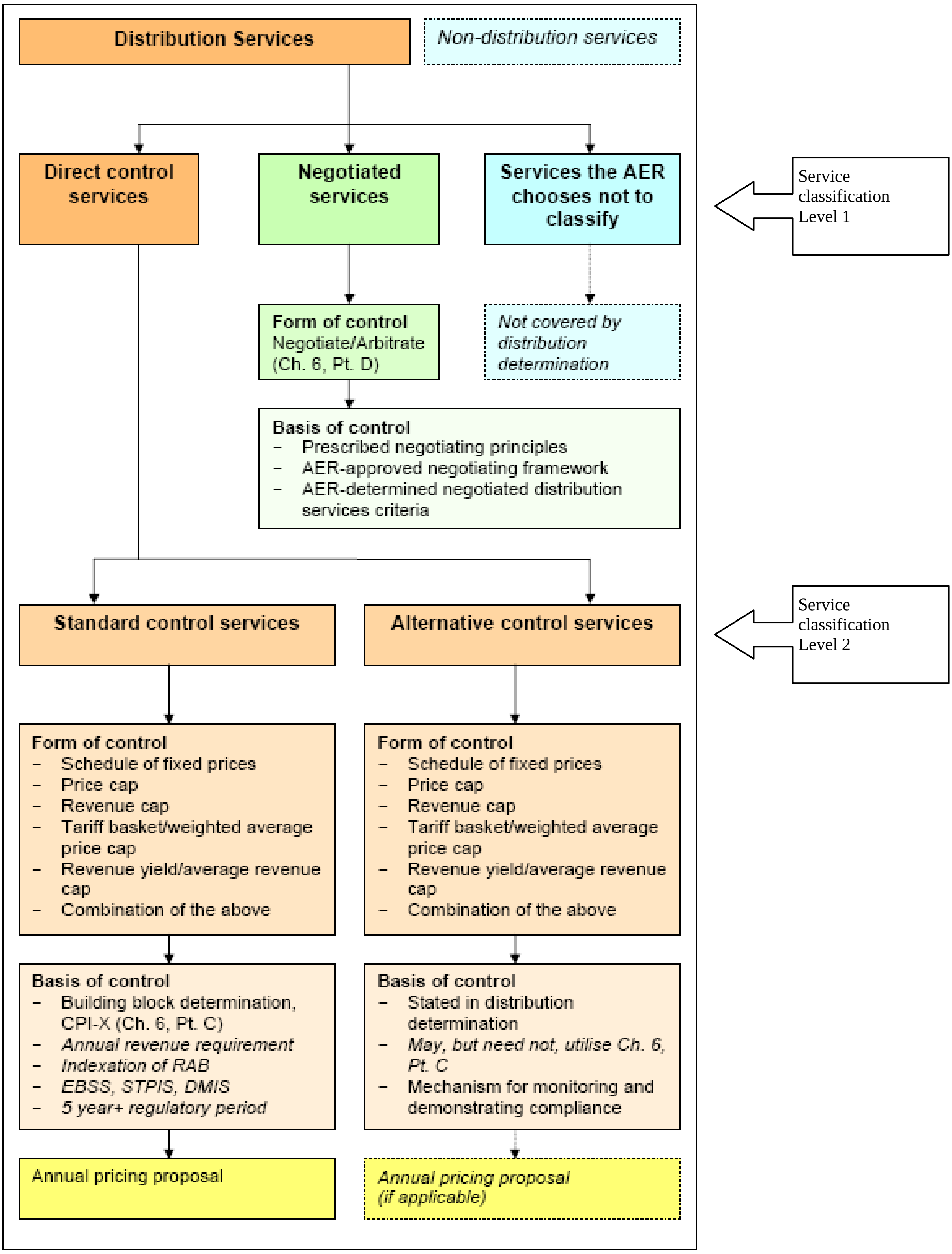
ii. an alternative control service.[3]

The class 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.

[3] NER, cl. 6.2.2(a)

Figure 1.1 **Service classification and control mechanisms**



Distribution services that the AER does not choose to classify will not be subject to the framework for economic regulation of distribution services set out in chapter 6 of the NER.[4]

[4] NER, cl. 6.2.1(a)

Terms and conditions of access to negotiated distribution services, including the price of those services, will be determined under the negotiate/arbitrate framework set out in chapter 6, Part D 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.[5] In the event of a dispute, the AER will arbitrate in accordance with the same criteria, and with regard to the approved framework.[6]

The distribution determination must impose a control on the price of, and/or revenue derived from, direct control services.[7] 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, or
6. a combination of any of the above.[8]

For standard control services, the control mechanism must be of the prospective CPI minus X form, or an incentive-based variant thereof. The basis of the control mechanism must be a building block determination made in accordance with chapter 6, part C of the NER.[9] The AER's distribution determination must include a decision on how compliance with the relevant control mechanism is to be demonstrated.[10]

The three incentive schemes developed by the AER under chapter 6 - the EBSS, STPIS and DMIS - apply only to standard control services.[11]

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.[12] The distribution determination must state the basis for the control mechanism applied to any alternative control services,[13] and must include a decision on how compliance with the control mechanism is to be demonstrated.[14]

For all direct control services, an annual pricing proposal must be submitted to, and approved, by the AER under chapter 6, part I.[15]

[5] NER, cl. 6.7.2
[6] NER, cl. 6.22.2(c)
[7] NER, cl. 6.2.5(a)
[8] NER, cl. 6.2.5(b)
[9] NER, cl. 6.2.5(a)
[10] NER, cl. 6.12.1(13)
[11] NER, cll. 6.5.8, 6.6.2, 6.6.3
[12] NER, cl. 6.2.6(c)
[13] NER, cl. 6.2.6(b)
[14] NER, cl. 6.12.1(13)
[15] NER, cl. 6.18.2(a)

1.3 Continuity between the 2005-10 and 2010-15 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 significant administrative costs on DNSPs, and to create short-term uncertainty for them and their customers and end users. This is recognised in transitional provisions in the NER and in the jurisdictional legislation that applies, and in jurisdictional derogations in chapter 9 of the NER.

The AER's objective is to minimise the impact of the transition to the new economic regulatory framework, both in 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.

1.4 Consultation on framework and approach paper

The framework and approach paper must be prepared in consultation with the relevant DNSP and with other interested stakeholders.

The AER must commence consultation on its framework and approach paper for ETSA Utilities on 30 June 2008, and must complete and publish the framework and approach paper by 30 November 2008.

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

Table 1.2 Process for preparation of and consultation on framework and approach paper

Publication of preliminary positions	**30 June 2008**
Submissions on preliminary positions close	11 August 2008
Public forum	*September 2008**
Publication of final framework and approach paper	**30 November 2008**

* Subject to sufficient interest from stakeholders.

1.4.1 Preliminary position paper

This preliminary position paper is the first step in the AER's consultation on the development of its framework and approach paper for ETSA Utilities.

- Chapter 2 sets out the AER's preliminary position on its approach to classification of distribution services provided by ETSA Utilities.
- Chapter 3 sets out the AER's preliminary position on 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 AER's preliminary position on its approach to the application to ETSA Utilities of the service target performance incentive scheme.
- Chapter 5 sets out the AER's preliminary position on its approach to the application to ETSA Utilities of the efficiency benefit sharing scheme.

- Chapter 6 sets out the AER's preliminary position on its approach to the application to ETSA Utilities of a proposed demand management incentive scheme or schemes.[16]

Chapter 7 of this paper sets out the AER's preliminary position on its approach to two other matters:

- the transition from pre-tax to post-tax revenue regulation
- recognition of carryovers accrued under the efficiency carryover mechanism applied to ETSA Utilities in its 2005-10 Electricity Distribution Price Determination (EDPD).

These matters have been identified as requiring particular clarification before ETSA Utilities submits its regulatory proposal to the AER in May 2009 and the distribution determination process commences. The AER therefore thinks it fit to give an indication of its likely approach to these matters in its framework and approach paper.

The AER seeks submissions on each of the preliminary positions identified in this paper by 11 August 2008. If sufficient interest is generated, the AER will consider holding a public forum in Adelaide in September to explore issues raised by stakeholders in their written submissions.

1.4.2 Framework and approach paper

Issues raised in submissions will be taken into account in developing the AER's framework and approach paper for ETSA Utilities, which must be published by 30 November 2008.

[16] The AER is in the process of developing a demand management incentive scheme that can be applied in the 2010-15 distribution determination for ETSA Utilities, and the 2010-15 distribution determinations for Energex and Ergon Energy. A proposed demand management incentive scheme for these DNSPs was released for consultation on 30 June 2008 at the same time as this preliminary position paper. The positions set out in this paper are based on the proposed scheme. The framework and approach paper released by the AER on 30 November will set out its likely approach to application of the final scheme, and will take into account submissions on both the proposed scheme and this position paper.

2 Classification of distribution services

2.1 Introduction

This chapter sets out the Australian Energy Regulator's (AER's) likely approach to the classification of ETSA Utilities' distribution services for the forthcoming regulatory control period. The AER may classify ETSA Utilities' distribution services as either direct control services or negotiated distribution services; services not classified by the AER are not regulated. The AER must further classify direct control services as either standard control services or alternative control services.

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[17], and
- whether the costs of providing the service should be recovered by ETSA Utilities through distribution use of system (DUOS) tariffs paid by all or most customers, or through separate tariffs paid by the individual customer requesting the service.[18]

The AER's role in service classification only determines the manner in which ETSA Utilities recovers the costs associated with the distribution services it provides – it does not determine the contestability of these services.[19] For example, the AER's classification of a distribution service as a direct control service does not make ETSA Utilities the exclusive monopoly provider of the service. Likewise, the AER's classification of a distribution services as a negotiated distribution service does not make the service contestable and open to supply by providers other than ETSA Utilities. Contestability is determined by legislation, the National Electricity Rules (NER), or other instruments, and is beyond the control of the AER. Contestability is, however, one of the factors the AER must consider in classifying services.

[17] 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, 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 six of the NER. The forms of control are discussed in greater detail in chapter 3 of this paper.

[18] 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. This is the basis on which the DNSP charges the retailer. Ultimately, however, the tariff structure charged to end-use customers is determined by the retailer.

[19] Contestability relates to whether or not a service is permitted by the laws or other regulatory instruments of the relevant jurisdiction to be provided by more than one DNSP.

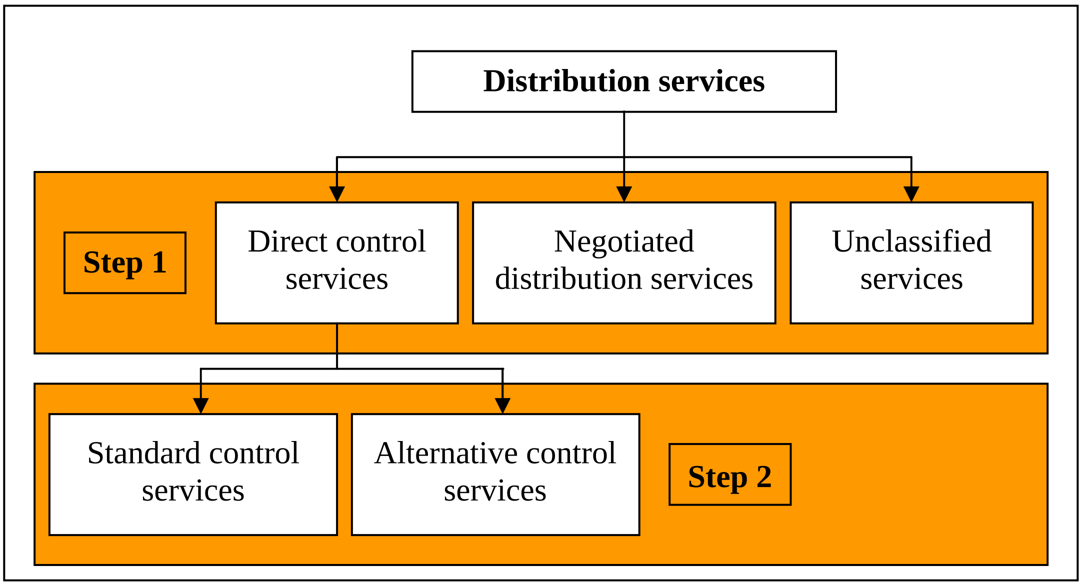
2.2 Requirements of the National Electricity Law and Rules

A distribution determination made by the AER 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.[20] The classification forms part of the distribution determination and operates only for the period for which the determination is made.[21] In its 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.[22]

The AER's discretion to depart from the likely approach to the classification of services set out in its framework and approach paper is qualified. The classification of services in the distribution determination must be as set out in the 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 classifications.[23]

The distribution service classifications available under the NER are illustrated in the figure below.

Figure 2.1 – Distribution service classification process



Source: NER[24]

Only services within the definition of distribution services in chapter 10 of the NER can be classified. The AER can not make a service that does not fall within that definition a distribution service by classifying it under the NER. Such services are outside the scope of the economic regulatory framework for distribution services in chapter 6 and the AER's distribution determination for ETSA Utilities.

[20] NER, cl. 6.12.1(1)
[21] NER, cl. 6.2.3
[22] NER, cl. 6.8.1(b)(1)
[23] NER, cl. 6.12.3(b)
[24] NER, chapter 6, Part B.

Distribution services can be grouped together for the purpose of classification, so that a single classification applies to each service in the group.[25]

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.[26] 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, 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

- the classification should be consistent with the previously applicable regulatory approach (if there has been no classification).[27]

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

The AER may classify distribution services as either:

- direct control services, or

- negotiated distribution services.[28]

Distribution services not classified by the AER as either of these are not regulated under the NER.[29]

When classifying distribution services as either direct control services or negotiated distribution services, the AER must have regard to:

- the form of regulation factors:

    - 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

[25] NER, cll. 6.2.1(b) and 6.2.2(b)
[26] NER, cll. 6.2.1(e) and 6.2.2(e)
[27] NER, cl. 6.2.1(d)
[28] NER, cl. 6.2.1(a)
[29] NER, cl. 6.2.1

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[30]

- 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)
- the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction), and
- any other relevant factor.[31]

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

The AER must further classify direct control services as either:

- standard control services, or
- alternative control services.[32]

In classifying direct control services as either standard control services or alternative control services, the AER must have regard to:

- the potential for development of competition in the relevant market and how the classification might influence that potential
- the possible effects of the classification on administrative costs of the AER, the DNSP and users or potential users
- the regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made
- the desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction)

[30] NEL, s. 2F
[31] NER, cl. 6.2.1(c)
[32] NER, cl. 6.2.2(a)

- the extent that costs of providing the relevant service are directly attributable to the customer to whom the service is provided, and
- any other relevant factor.[33]

2.3 Summary of current arrangements

ETSA Utilities' current service classifications are set out in the 2005-10 Electricity Distribution Price Determination (EDPD), which was determined by the Essential Services Commission of South Australia (ESCOSA) in accordance with the National Electricity Code (NEC).

In the EDPD, ESCOSA defined distribution services as:

> all services provided by a *distribution system* or *ETSA Utilities* which are associated with the conveyance of electricity through the *distribution system* including, without limitation, *connection services*, *network services*, *metering services*, *entry services*, *distribution network use of system services*, *exit services*, and *network services* which are provided by part of a *distribution system*. [34]

Distribution services were divided into prescribed distribution services and excluded services. Prescribed distribution services are typically provided to all customers, or to a broad class of customers, and are generally available only from ETSA Utilities. Excluded services are generally provided at the request of, or for the benefit of, specific customers. They are 'excluded' in the sense that the costs associated with the delivery of these services are not recovered through the control mechanism applicable to ETSA Utilities' prescribed distribution services, which is currently a hybrid form of average revenue cap.[35]

ESCOSA defined prescribed distribution services as '[all] distribution services other than excluded services'[36]. An exhaustive list of excluded services was included in the EDPD. ESCOSA also built in a 'flexibility clause' allowing additional distribution services to be added to the list of excluded services during the regulatory period, should appropriate services be identified.[37] No additional excluded services have been included at this time.

ESCOSA noted that classifying services in this manner avoided many of the definitional issues associated with prescribed distribution services, instead focussing

[33] NER, cl. 6.2.2(c)
[34] ESCOSA, *2005-2010 electricity distribution price determination – part B – price determination*, April 2005, pp.24-25. The italicised words in this paragraph are defined in the EDPD and reproduced in appendix A of this paper.
[35] ESCOSA, *Electricity distribution price review: defining prescribed and excluded services – discussion paper*, April 2003, pp.1-2.
[36] ESCOSA, *2005-2010 electricity distribution price determination – part B – price determination*, April 2005, p.29. ESCOSA also included in its definition of distribution services certain services associated with the establishment of and operation of retailer of last resort (ROLR) capabilities. ETSA Utilities' current role as the ROLR in South Australia is discussed in more detail in section 2.4.5.
[37] ESCOSA, *2005-2010 electricity distribution price determination – part B – price determination*, April 2005, pp.25-26.

the definitional emphasis on excluded services. ESCOSA noted that this approach was also consistent with the approach of other jurisdictional regulators at the time.[38]

The table below summarises ETSA Utilities' current service classifications. A complete description of these classifications can be found in appendix A.

Table 2.1 – ETSA Utilities' current service classifications

Service category	Prescribed distribution services	Excluded services
Network services	Network services at mandated standard	Network services at higher than mandated standard
Connection services	Connection services at mandated standard	Connection services at higher than mandated standard New or upgraded connection services (to the extent the user is required to make a financial contribution)
Metering services	Small customer standard metering services excluding special meter reads	Small customer non-standard metering services Small customer special meter reads (including monthly reads) Large customer metering services
Public lighting services		Operation and maintenance Provision of assets, operation and maintenance 'Energy only' service
Other services		Provision of stand-by or temporary supply Asset relocations Disconnections and reconnections Recoverable asset repairs High load escorts Pole and duct rental Feeder standby service Any other distribution service approved by ESCOSA to be an excluded service

Source: ESCOSA[39], AER analysis

[38] ESCOSA, *Electricity distribution price review: defining prescribed and excluded services – discussion paper*, April 2003, p.6.

ESCOSA applied a (hybrid) average revenue cap to ETSA Utilities' prescribed distribution services as required by the Electricity Pricing Order (EPO).[40] Under the NEC, the form of regulation to be applied to prescribed distribution services included that it be 'of the prospective CPI minus X form, or some incentive-based variant of the CPI minus X form'[41] ESCOSA determined the X-factor using a building block approach.

The NEC also provided that excluded services should be regulated in a more 'light handed' manner than that applied to prescribed distribution services, with the form of regulation for excluded services determined by the jurisdictional regulator.[42] The form of regulation ESCOSA applied to ETSA Utilities' excluded services combined pricing principles, price monitoring and a negotiate-arbitrate framework. ETSA Utilities is presently required to price excluded services on a 'fair and reasonable basis', and publish a list of prices for its excluded services, where available, annually. In the event of a dispute ESCOSA determines the price to be charged by ETSA Utilities for a particular excluded service based on the same pricing principles. Subsequent to the EDPD, ESCOSA published a guideline on the form of regulation applicable to excluded services that detailed the form of regulation for excluded services that was set out in the EDPD.[43]

2.4 Issues and AER's considerations

2.4.1 Distribution services[44]

In order to classify distribution services it is necessary to first 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*'.[45]

'Distribution system' is also defined in the NER. The definition of distribution system contains additional defined terms. Effectively, distribution services are services provided by means of, or in connection with, a distribution network, together with the connection assets associated with the distribution network, which are connected to another transmission or distribution system.

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

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[39] ESCOSA, *2005-2010 electricity distribution price determination – part B – price determination*, April 2005.
[40] EPO, cl. 7.2(a). The EPO set out the tariffs ETSA Utilities could charge during the 2000-05 regulatory control period. It also includes certain requirements to be adopted during subsequent and future regulatory control periods. The requirement that an average revenue cap be applied to ETSA Utilities prescribed distribution services expires at the end of the 2005-10 regulatory control period.
[41] NEC, cl. 6.10.5.
[42] NEC, cl. 6.10.4.
[43] ESCOSA, *Excluded services regulation – distribution – electricity industry guideline no. 14*, December 2005.
[44] The definition of distribution services in this section paraphrases that contained in the 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.
[45] NER, chapter 10.

assets are owned, controlled or operated by the DNSP, excluding services provided over a transmission network.

Distribution services appear to include network services, connection services, metering services, public lighting services and certain other services.

2.4.2 Considerations relevant to steps 1 and 2

2.4.2.1 Requirement to classify a service of a specified kind in a particular way

At both steps of classification, if the NER requires 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.[46] This requirement overrides all other considerations in chapter 6 of the NER. The AER is not aware of the NER requiring a distribution service provided by ETSA Utilities to be classified in a particular way pursuant to these clauses.

2.4.2.2 Presumption in favour of prior classification or 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 begins with a presumption in favour of the prior classification, or classification consistent with the previously applicable regulatory approach (as the case may be).[47] The AER's assessment then involves the analysis of whether a different classification is clearly more appropriate, having regard to the factors in the NER.

ETSA Utilities' distribution services have not been previously classified under the NER, meaning that it is the presumption in favour of classification consistent with the previously applicable regulatory approach that is relevant. This presumption suggests that:

- ETSA Utilities' prescribed distribution services should be classified as direct control services, and further classified as standard control services, for the next regulatory control period, and
- ETSA Utilities' excluded services should be classified as negotiated distribution services for the next regulatory control period,

unless a different classification is clearly more appropriate.

The first of these presumptions has been formed on the basis that the form of regulation applicable to standard control services under the NER is consistent with the form of regulation presently applied to ETSA Utilities' prescribed distribution services. Both are regulated under a direct control mechanism, incorporate a CPI-X framework (or variant thereof) where the X-factor is determined according to a building block approach, and tariffs are subject to the annual approval of the regulator.

[46] NER, cll. 6.2.1(e) and 6.2.2(e).
[47] NER, cll. 6.2.1(d) and 6.2.2(d).

The second of these presumptions has been formed on the basis that the form of regulation applicable to ETSA Utilities' excluded services is closer to that of negotiated distribution services than that for the other service classifications available under the NER. Parts D and L of chapter 6 of the NER provide that the price of a negotiated distribution service is to reflect certain pricing principles, and in the case of dispute is to be determined by the regulator consistent with those pricing principles. This framework is broadly consistent with that presently applied to ETSA Utilities' excluded services. In contrast, the forms of control available for alternative control services under the NER are direct controls on price or revenue, rather than a negotiate-arbitrate framework.

Under the NER, the AER must make a positive decision to classify a service as a direct control or negotiated distribution service, or as a standard control or alternative control service. The 'default' approach adopted by ESCOSA, which would equate to classifying all distribution services as direct control services (and further classified as standard control services), except for those specifically identified as negotiated distribution services, is not available under the NER. Additionally, the flexibility which allowed ESCOSA to add additional services as excluded services (i.e. negotiated distribution services) during the regulatory control period is not available to the AER under the NER.

Accordingly, even where no other classifications are found to be clearly more appropriate, the way in which the classifications are defined still needs to change. The AER must separately list direct control and negotiated distribution services, and standard control and alternative control services. In the absence of 'default' classifications, the AER is aware of the need to classify services in such a way as to allow flexibility to ETSA Utilities to alter the exact specification (but not the nature) of a service during the regulatory control period, whilst at the same time providing certainty as to how specific services, particularly new services that arise during the regulatory period, are classified.

This balance could be achieved by grouping services for the purpose of classification as provided for by the NER.[48] This approach to service classification has the advantage of classifying a class of activities, rather than the specific activities, allowing the specific definition or magnitude of services to change whilst maintaining the desired classification. Such broad classifications could be combined with a list of specific services that are included (but not limited to) that classification grouping.

2.4.3 Step 1 – Division of distribution services into direct control, negotiated distribution and unregulated services

As stated, the presumption is that ETSA Utilities' prescribed services will become direct control services, and its excluded services will become negotiated distribution services. ETSA Utilities' current prescribed distribution services and excluded services are summarised in table 2.1 above, and detailed in appendix A.

This section analyses whether a different classification is clearly more appropriate for any of these services.

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

2.4.3.1 Network services

A network service is defined in the NER as a '…distribution service associated with the conveyance, and controlling the conveyance, of electricity through the network'[49].

Network services predominantly relate to services provided over the shared network used to service all network users connected to it. Such services may include the construction, maintenance, operation, planning and design of the shared network. Network services are delivered though 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 and 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' thus encompasses much of a DNSP's distribution services.

Current classifications

Effectively ESCOSA classified all 'standard' network services as prescribed distribution services and all 'non-standard' network services as excluded services.

ESCOSA defined network services as:

> ***Network services*** means each or all of:
>
> i) the provision of *network capability* to support the delivery of electricity to *distribution connection points* up to the *agreed maximum demand* for the *connection point* (where applicable) or otherwise at the level of demand at which electricity is generally delivered to or taken from the *distribution connection point*;
>
> ii) the management, maintenance and operation of the *distribution network* to provide the *network capability* referred to in paragraph (a) of this definition; and
>
> iii) such additional activities as are necessary to ensure the integrity of the *distribution network* and maintain the *network capability* to support the delivery of electricity to and, where applicable, to take electricity from, *distribution connection points*,
>
> using *good electricity practice* and in accordance with the requirements of the *Code*, the *Electricity Distribution Code* and any other *applicable laws*.[50]

All network services were classified as prescribed distribution services except for the following non-standard services which were classified as excluded services. Excluded network services were limited to network services provided:

> iv) …at the request of a *distribution network user*:

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[49] NER, chapter 10.

[50] ESCOSA, *2005-2010 electricity distribution price determination – part B – price determination*, April 2005, pp.28-29. Italicised terms are as defined in the EDPD.

(1) with higher quality or reliability standards than are required by the *Code*, the *Electricity Distribution Code*, the *Electricity Metering Code* or any other *applicable laws*; or

(2) in excess of levels of service or plant ratings required to be provided by *ETSA Utilities'* assets.[51]

Issues and AER's considerations

Significant barriers to entry exist for the provision of network services, limiting the potential for these services to be competitively supplied by providers other than ETSA Utilities.[52] The significant capital costs of entry, and the economies of scale and scope available to ETSA Utilities as the incumbent, are highly likely to make duplication of ETSA Utilities' shared network by an alternative service provider both commercially unviable and economically inefficient. The economies of scale and scope available to ETSA Utilities are also likely to prevent augmentation of the network being competitively provided by an alternative provider. In many circumstances, the augmentation of ETSA Utilities' shared network by an alternative provider is also likely to be technically unfeasible.

Substitutes for using these shared network services are few, and are likely limited to embedded generation, switching the energy source to gas, or switching the connection point to the transmission network. These are unlikely to be viable commercial options in most instances, especially for most existing large customers and all small customers.[53]

These factors contribute to the likely outcome of ETSA Utilities possessing significant market power in the provision of network services and consequently requiring a direct form of price control over the provision of network services. Even a high degree of information available to users would not neutralise the lack of countervailing power caused by these other factors.[54]

Whilst there are few substitutes for 'standard' network services, 'non-standard' network services are likely to be substitutable in that customers could substitute these services for standard network services.[55] It is difficult to forecast the costs and magnitude of these services, as by their very nature these aspects will depend on the characteristics desired by individual customers requesting these services. It is therefore appropriate that these services be regulated under a negotiate-arbitrate framework. Whilst most of these non-standard network services are likely to be non-contestable, it is noted that ETSA Utilities will be required to charge for negotiated distribution service in accordance with the pricing principles set out in the NER, which include that the price should be based on the costs incurred in providing that service.[56]

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[51] ESCOSA, *2005-2010 electricity distribution price determination – part B – price determination*, April 2005, p.35. Italicised terms are as defined in the EDPD.
[52] NER, cl. 6.2.1(c)(1).
[53] NER, cl. 6.2.1(c)(1).
[54] NER, cl. 6.2.1(c)(1).
[55] NER, cl. 6.2.1(c)(1).
[56] Specifically, cll. 6.7.1(3)-(4) provide that the price differential between a non-standard shared distribution service and equivalent standard service should reflect the cost differential between providing the services.

AER's preliminary position

The AER's preliminary position is that ETSA Utilities' network services should be classified in a manner which is consistent with the previously applicable regulatory approach, as no other classification is clearly more appropriate.

On this basis, 'standard' network services should be classified as direct control services, and 'non-standard' services should be classified as negotiated distribution services. That is, all network services should be classified as direct control services except for:

- services provided at the request of a customer at higher quality or reliability standards, or lower quality or reliability standards, than are required by the NER, the Electricity Distribution Code, or any other applicable regulatory instruments, or
- services provided at the request of a customer in excess of levels of service or plant ratings required to be provided by ETSA Utilities' assets,

which should be classified as negotiated distribution services.

2.4.3.2 Connection services

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.[57]

Current classifications

The effect of the default classification approach adopted by ESCOSA, discussed above in section 2.3, is that 'standard' connection services have been classified as prescribed distribution services, and 'non-standard' connection services as excluded services. Connection services associated with new or upgraded connection points were also classified as excluded services.

ESCOSA defined connection services as:

> ***Connection services*** means either or both of the:
>
> i) provision of capability at each *connection point* (by means of the *connection assets* for the *distribution connection point*) to deliver electricity to or take electricity from the *connection point* using *connection assets*;
>
> ii) management, maintenance and operation of *connection assets*, so as to provide the capability referred to in paragraph (a) of this definition,

[57] NER, chapter 10.

> using *good electricity industry practice* and in accordance with the requirements of the *Code*, the *Electricity Distribution Code*, the *Electricity Metering Code* and any other *applicable laws*.[58]

Connection services were classified by default as prescribed distribution services except for the following non-standard services, which were explicitly classified as excluded services. Excluded connection services were limited to connection services provided:

> iii) …at the request of a *distribution network user*:
>
> (1) with higher quality or reliability standards than are required by the *Code*, the *Electricity Distribution Code*, the *Electricity Metering Code* or any other *applicable laws*; or
>
> (2) in excess of levels of service or plant ratings required to be provided by *ETSA Utilities'* assets.[59]

Connection services associated with the provision of new or upgraded connection points, meaning:

> iv) The:
>
> (1) provision of a new *connection point*, including associated extension or augmentation of the *distribution network*; or
>
> (2) upgrading of the capability of a *connection point*, including by extension or augmentation of the *distribution network*,
>
> to the extent that a *distribution network user* is required to make a financial contribution in accordance with the *Electricity Distribution Code*.
>
> v) Responding to an enquiry in relation to a *connection point* referred to in paragraph 1.2(a)(i).
>
> vi) Providing technical specifications in relation to a *connection point* referred to in paragraph 1.2(a)(ii),[60]

were also classified as excluded services.

Issues and AER's considerations

Whilst there are few substitutes for 'standard' connection services, 'non-standard' connection services are likely to be substitutable in that customers could substitute these services for standard connection services.[61] It is difficult to forecast the costs and magnitude of these services, as by their very nature these aspects will depend on the characteristics desired by individual customers requesting these services. It is therefore appropriate that these services be regulated under a negotiate-arbitrate framework. Therefore, the AER is inclined to classify standard connection services as

[58] ESCOSA, *2005-2010 electricity distribution price determination – part B – price determination*, April 2005, p.24. Italicised terms are as defined in the EDPD.
[59] ESCOSA, *2005-2010 electricity distribution price determination – part B – price determination*, April 2005, p.35. Italicised terms are as defined in the EDPD.
[60] ESCOSA, *2005-2010 electricity distribution price determination – part B – price determination*, April 2005, p.35. Italicised terms are as defined in the EDPD.
[61] NER, cl. 6.2.1(c)(1).

direct control services and non-standard connection services as negotiated distribution services.

The current classification of connection services associated with new or upgraded connection points as excluded services is limited to circumstances where:

> …a *distribution network user* is required to make a financial contribution in accordance with the *Electricity Distribution Code*.[62]

This clause of the EDPD relates to capital contributions made by customers to ETSA Utilities for new or upgraded connection points. The provisions regulating the amount customers contribute to new or upgraded connection points is set out in chapter 3 of the Electricity Distribution Code, which is a jurisdictional regulatory instrument. A derogation in the NER preserves these arrangements relating to capital contributions for South Australia into the future.[63]

The Electricity Distribution Code sets a cap on the amount ETSA Utilities can charge a customer for a new or upgraded connection point and the associated extension or augmentation of the distribution network.[64] This cap is determined as the sum of:

- the cost of the connection assets as quoted by ETSA Utilities or determined according to a tender process (customers may call for tenders from providers other than ETSA Utilities for the design and construction of connection assets)

- *plus* the cost of any associated extension to the distribution network as quoted by ETSA Utilities or determined according to a tender process (customers may call for tenders from providers other than ETSA Utilities for the design and construction of associated extension works)

- *plus* the customer's allocation of any associated augmentation to the distribution network

- *plus* the amount determined as the customer's contribution to upstream customers

- *minus* the 'distributor's rebate'.[65]

The distributor's rebate is an amount that offsets the cost of the new or upgraded connection point to determine whether or not the customer is required to contribute directly to this cost. For residential customers the distributor's rebate equals $3 000. For non-residential customers the distributor's rebate equals whichever is the greater of $3 000 or a fixed amount determined from time to time by the regulator plus the incremental DUOS charges ETSA Utilities expects to earn over the following three years.

The ability for customers to elect an alternative provider to design and construct the connection assets and associated extension works provides customers with some

[62] ESCOSA, *2005-2010 electricity distribution price determination – part B – price determination,* April 2005, p.35. Italicised terms are as defined in the EDPD.
[63] NER, cl. 9.29.6.
[64] ESCOSA, *Electricity Distribution Code,* version 6, December 2006, p.A-32.
[65] ESCOSA, *Electricity Distribution Code,* version 6, December 2006, p.A-32.

countervailing power.[66] The information ETSA Utilities is required to provide the customer under the Electricity Distribution Code also lessens the barriers to entry for these services.[67]

ETSA Utilities has informed the AER that since the beginning of the current regulatory control period (1 July 2005), ETSA Utilities has reported 165 formal complaints raised by customers, relating primarily to customer connection charges. ETSA Utilities states that all of these complaints have been resolved by internal processes, with none being escalated to ESCOSA for arbitration. In relative terms, ETSA Utilities notes that more than 20 000 customer connections are processed per annum, and concerns in relation to pricing have been raised for less than 0.25% of these.

The low level of disputes may reflect that the current service classifications and form of regulation have been effective.[68] Alternatively, it could reflect a lack of customer awareness of the availability of the arbitration process, or suggest that the costs (in terms of time and money) to participate in the dispute resolution process are prohibitive, particularly for small customers. Notwithstanding these potential concerns, the AER has no evidence to suggest the current classification and form of regulation are not effective and accordingly the AER is inclined to classify connection services associated with new or upgraded connection points as negotiated distribution services, acknowledging the form of regulation for these services would combine the relevant provisions of the Electricity Distribution Code and Parts D and L of chapter 6 of the NER.

AER's preliminary position

The AER's preliminary position is that ETSA Utilities' connection services should be classified in a manner which is consistent with the previously applicable regulatory approach as no other classification is clearly more appropriate.

On this basis, 'standard' connection services should be classified as direct control services, and 'non-standard' services should be classified as negotiated distribution services. That is, connection services should be classified as direct control services except for those services provided at the request of a customer:

- with higher quality or reliability standards, or lower quality or reliability standards, than are required by the NER, the Electricity Distribution Code, or any other applicable regulatory instrument, or

- in excess of levels of service or plant ratings required to be provided by ETSA Utilities' assets,

which should be classified as negotiated distribution services.

In addition, connection services associated with new or upgraded connection points should be classified as negotiated distribution services.

[66] NER, cl. 6.2.1(c)(1).
[67] NER, cl. 6.2.1(c)(1).
[68] NER, cl. 6.2.1(c)(2).

2.4.3.3 Metering services

Each connection point in the NEM must have a metering installation.[69] Metering services are not explicitly defined in the NER, but are generally accepted as falling into two broad categories:

- meter provision services – the provision, installation, routine inspecting and maintenance of metering installations, and
- energy (ie. metering) data services (which are defined in the NER) – which involve:
  - collation of energy data from the meter or meter / associated data logger
  - the processing of the energy data in the metering installation database
  - storage of the energy data in the metering installation database, and
  - the provision of access to the data for those parties that have rights of access to the data.[70]

Metering services in the NEM are also distinguished by the tier structure of the connection point and the type structure of the metering installation. There are two different tiers and six different types.

The tier structure refers to the billing relationship between the retailer and end-use customer. More precisely it refers to whether or not the end-use customer purchases its electricity in its entirety from the local retailer[71]. The two different tiers of connection points are listed in the table below.

Table 2.2 Tier structure of connection points

Tier	Description
1st tier	A connection point where the end-use customer purchases its electricity directly and in its entirety from the local retailer*
2nd tier	A connection point where the end-use customer purchases its electricity at least in part from a retailer not the local retailer* or from the spot market

Source: NER, AER analysis
* In South Australia the local retailer is AGL South Australia

For type 1-4 metering installations, the type structure refers to the quantity of electricity flowing through the connection point. For type 5-7 metering installations, the type structure refers to both the quantity of electricity flowing through the

[69] NER, cl. 7.3.1A(a).
[70] NER, chapter 10.
[71] The local retailer is, in relation to a local area, the customer who is either – a business unit or related body corporate of the relevant local network service provider; or, responsible under the laws of the relevant participating jurisdiction for the supply of electricity to franchise customers in that local area; or, if neither of these apply such other customer as NEMMCO may determine. In South Australia the local retailer is AGL South Australia.

connection point and other characteristics. The six different types of metering installations are listed in the table below.

Table 2.3 Type structure of metering installations

Type	Description (i.e. quantity of electricity flowing through connection point)
Type 1	Flows greater than 1 000 GWh per annum
Type 2	Flows between 100 and 1 000 GWh per annum
Type 3	Flows between 0.75 and 100 GWh per annum
Type 4	Flows less than 0.75 GWh per annum
Type	**Description**
Type 5	Interval meter, read manually, with a load cap set by the jurisdiction between 0 and 0.75 GWh per annum
Type 6	Accumulation meter, read manually or electronically, with a load cap set by the jurisdiction between 0 and 0.75 Gwh per annum
Type 7	Unmetered connection point

Source: AEMC[72]

Type 4 applies to metering installations with flows less than 0.75 GWh across all jurisdictions, except where these metering installations are otherwise a type 5 or type 6 metering installation. Type 5 and 6 metering installations have a maximum range of between 0 and 0.75 GWh per annum, with the actual range set by individual jurisdictions. The lower the range for type 5 and 6 metering installations, the greater the coverage for type 4 metering installations.

Presently, the range for type 5 metering installations has been set at between 0 and 160 MWh (0.16 GWh) in all jurisdictions but Queensland, where the range is between 0 and 100 MWh.[73]

Current classifications

ESCOSA did not consider that different service classifications were warranted on the basis of function (i.e. meter provision services or energy data services) or the tier structure of connection points (i.e. 1st tier or 2nd tier). Distinction between service classifications for metering services was limited to the type structure of metering installations.

ESCOSA considered that given there were some 750 000 small customers (those consuming less than 160MWh of electricity per annum) with metering installations types 6 or 7, there were clear economies of scale attached to the provision of metering

[72] AEMC, *Rule determination – national electricity amendment integration of NEM metrology requirements rule 2008*, 6 March 2008, pp.7-8.
[73] AEMC, *Rule determination – national electricity amendment integration of NEM metrology requirements rule 2008*, 6 March 2008, p.8.

services for these types of metering installations. ESCOSA classified these metering services as prescribed distribution services.[74]

ESCOSA classified metering services to small customers in respect of meters meeting the requirements of metering installations types 1-5, or metering installations type 6-7 containing a meter different to the type of meter ETSA Utilities would ordinarily install (including prepayment meter systems) as excluded services. However these services were only classified as excluded services in terms of the incremental cost of providing these services over and above the costs of metering services for meters meeting the requirements of metering installations types 6 and 7. As all small customers would already be paying for the provision of a type 6 or 7 metering installation (i.e. a basic metering service), ESCOSA limited these excluded services to the incremental cost of providing these services to avoid a double recovery by ETSA Utilities of the costs associated with these services. ESCOSA also classified special meter readings (including monthly reads) to small customers, which are energy data services, as excluded services.

ESCOSA classified all metering services to large customers (those consuming more than 160MWh of electricity per annum) as excluded services.[75]

There were two exceptional cases that did not fall under the classifications described above. Both of these cases were sub-categories of metering installations types 1-4, where for legacy reasons it was considered inappropriate to classify these services as excluded services:[76]

- Customers consuming between 160 and 750MWh per annum who have types 1-4 metering installations provided prior to 1 July 2000
- Customers consuming more than 750MWh per annum who have types 1-4 metering installations provided prior to 1 July 2005

The associated costs of meter provision in these cases had already been included in the prescribed (regulated) asset base and partially recovered during the 2000-05 regulatory period. ESCOSA retained these meter provision services as prescribed distribution services to avoid customers inappropriately paying again for these services.

Issues and AER's considerations

Under the NER, the person responsible for the provision, installation and maintenance of a metering installation for all customers including 1st tier and 2nd tier customers is referred to as the responsible person.[77]

As the local network service provider (LNSP), ETSA Utilities is the responsible person for type 5-7 metering installations in South Australia and must, at its own

[74] ESCOSA, 20*05-2010 electricity distribution price determination – part A – statement of reasons, April 2005*, p.19.
[75] ESCOSA, 20*05-2010 electricity distribution price determination – part A – statement of reasons, April 2005*, p.20.
[76] ESCOSA, 20*05-2010 electricity distribution price determination – part A – statement of reasons, April 2005*, pp.20-21.
[77] NER, cl. 7.2.1.

initiative or at the request of a market participant[78], provide the market participant with a standard set of terms and conditions that are 'fair and reasonable', on which it will act as the responsible person for these metering installations. A market participant must accept ETSA Utilities' offer or may dispute the offer in accordance with rule 8.2.[79] Type 5-7 metering services are provided principally to small customers.[80]

These provisions of the NER provide that the provision, installation and maintenance of type 5-7 metering installations are not contestable, and are the exclusive responsibility of the LNSP. This regulatory barrier to entry, coupled with the non-substitutable nature of these services, is highly likely to provide ETSA Utilities with a significant degree of market power in the provision of these services.[81] A high degree of information available to users would not significantly increase users' countervailing market power, which is little if any for these services.[82] The AER is therefore inclined to classify all type 5-7 meter provision services as direct control services. Whilst type 6-7 metering services are currently classified as prescribed distribution services, type 5 metering services are currently classified as excluded services. At this stage, the AER's preliminary position is to retain the classifications that are consistent with the previously applicable regulatory approach, however in response to submissions the AER will consider whether classifying type 5 metering services going forward as direct control services is clearly more appropriate. These services can all be considered to be standard (as opposed to non-standard) small customer meter provision services.

Whilst there are few substitutes for standard small customer meter provision services, non-standard meter provision services are likely to be substitutable, in that customers could substitute these services for standard meter provision services.[83] It is difficult to forecast the costs and magnitude of these services, as by their very nature these aspects will depend on the characteristics desired by the individual customers requesting these services. It is therefore appropriate that access to, and the price of, these services be regulated under a negotiate-arbitrate framework. This is consistent with the previously applicable regulatory approach.

For type 1-4 metering installations, a market participant may request ETSA Utilities (as the LNSP) to be the responsible person for these metering installations. If a request is received, ETSA Utilities must offer to act as the responsible person and provide the market participant with the terms and conditions on which the offer is made.[84] Unlike type 5-7 metering installations, there is no requirement that this offer be fair and reasonable.

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[78] A market participant is a person who is registered by NEMMCO as a Market Generator, Market Customer or Market Network Service Provider under chapter two of the NER.
[79] NER, cl. 7.2.3.
[80] Section four of the *Electricity Act 1996 (South Australia)* provides that 'small customer means a customer with an annual electricity consumption level less than the number of MWh per year specified by regulation for that purpose, or any customer classified by regulation as a small customer'. Section 4B of the *Electricity (General) Regulations 1997 (South Australia)* define a small customer as one whose annual electricity consumption level for a connection point is less than 160 MWh.
[81] NER, cl. 6.2.1(c)(1).
[82] NER, cl. 6.2.1(c)(1).
[83] NER, cl. 6.2.1(c)(1).
[84] NER, cl. 7.2.3.

These provisions of the NER provide that the provision, installation and maintenance of type 1-4 metering installations are contestable, in that a market participant can choose whether it elects to be, or requires the LNSP to be, the responsible person for these metering installations. This may provide the market participant with some countervailing power, as ETSA Utilities faces a loss of revenue should a market participant chose an alternative provider.[85] The installation and maintenance of a metering installation must be carried out by a metering provider who is accredited and registered by NEMMCO.[86]

Should a market participant elect to be the responsible person, it would be required to engage (or to be) a registered metering provider for the installation and maintenance of these metering installations. As at February 2008, 18 metering providers were registered with NEMMCO who were accredited to provide, install and maintain certain type 1-4 metering installations.[87] Most of these registered metering providers appear to be, or be associated with, a DNSP. From this information alone the AER is unable to assess the competitiveness of metering provision services in South Australia for type 1-4 metering installations. That is, whilst there are 17 potential alternative providers (18 if ETSA Utilities is included) it is unclear to what extent these potential alternative providers compete for the provision of type 1-4 meter provision services in South Australia. Acknowledging that these services are contestable, the AER is inclined to classify these services as negotiated distribution services, which is consistent with the previously applicable regulatory approach, even though at present the actual level of competition is unclear.

Due to the interdependencies of meter provision and energy data services, the AER considers that, in general, energy data services should be classified consistently with the related meter provision service.[88] Such classifications are also consistent with the previously applicable regulatory approach.

The AER considers it is appropriate to classify the two exceptional cases described above as direct control services, which is consistent with the previously applicable regulatory approach. Reclassifying these services as negotiated distribution services would likely require adjustments to ETSA Utilities' regulatory asset base. Whilst this operation is allowed under the NER, it is not desirable.[89]

AER's preliminary position

The AER's preliminary position is that ETSA Utilities' metering services should be classified in a manner which is consistent with the previously applicable regulatory approach, as no other classification is clearly more appropriate.

The AER considers that different service classifications are not warranted based on the distinction of function (i.e. meter provision services or energy data services) or whether the service is provided to a 1st tier or 2nd tier customer. The AER considers service classification distinctions should be isolated to the type structure of metering installations, whether the customer is small or large, and whether the service is

[85] NER, cl. 6.2.1(c)(1).
[86] NER, cll. 7.4.1-7.4.2.
[87] NEMMCO, *Registered category A and B metering providers – national electricity market*, February 2008.
[88] NER, cl. 6.2.1(c)(1).
[89] NER, cl. 6.2.1(c)(4).

standard or non-standard. This is consistent with the regulatory approach currently adopted by ESCOSA.

The AER's preliminary position is to:

- classify standard small customer metering services (type 6-7 metering installations) as direct control services
- classify non-standard small customer metering services, and type 5 metering installation services, as negotiated distribution services
- classify all large customer metering services as negotiated distribution services, and
- classify the two exceptional cases of type 1-4 meter provision services identified above as direct control services.

2.4.3.4 Public lighting services

Public lighting services are not defined in the NER, however, public lighting services currently provided by ETSA Utilities include:

- the replacement of lamps in customer owned streetlights – in South Australia this is referred to as 'customer lighting equipment rate' (CLER), and
- the provision of public lighting assets, along with the operation and maintenance of those assets – in South Australia this is referred to as 'street lighting use of system' (SLUOS)[90]

A third category of public lighting service, referred to as 'energy only', also exists. This service relates to the transportation of electricity through the distribution system for use in public street lights, the maintenance of data related to these lights in ETSA Utilities public lighting database, and recording and dispatch of faults related to these lights to the customer.

Current classifications

ESCOSA classified both the CLER and SLUOS public lighting services as excluded services. CLER services were subject to the same form of regulation as the other excluded services. For SLUOS services, the form of regulation also combined pricing principles, price monitoring and a negotiate-arbitrate approach, however the specifics of this approach differed from that applied to other excluded services.[91]

Prices for SLUOS were also required to be 'fair and reasonable', however for these services ESCOSA considered that fair and reasonable would be taken as:

- any price that has been negotiated between ETSA Utilities and a customer (or a representative of a group of customers), or

[90] ESCOSA, 20*05-2010 electricity distribution price determination – part A – statement of reasons, April 2005*, p.25.
[91] ESCOSA, 20*05-2010 electricity distribution price determination – part A – statement of reasons, April 2005*, p.28.

- in the event that agreement is not reached and there is a dispute, the price that is determined by ESCOSA.

The side constraint on prices for SLUOS also differed from that for other excluded services. The annual price movement for any particular SLUOS service is restricted to no more than CPI (unless otherwise approved by ESCOSA).

As is the case for other excluded services, ETSA Utilities is required to publish a price list for SLUOS services annually.

Issues and AER's considerations

The AER understands that it is possible for CLER services, which effectively relate to changing the lamp in a public streetlight, to be easily provided by providers other than ETSA Utilities, or indeed by customers themselves. Customers for these services are for the most part local councils and Transport SA. It may be that the barriers to entry for CLER services are very low and little, if any, regulation is warranted. At this stage, the AER's preliminary position is to classify CLER services as negotiated distribution services. Taking account of any submissions on this matter, the AER will consider whether a decision not to classify these services is clearly more appropriate, effectively removing any economic regulation under the NER from these services.

In terms of revenue, public lighting services constitute ETSA Utilities' second most significant excluded service, after new and upgraded connection point services. In 2006-07, ETSA Utilities earned nearly $14m from SLUOS and CLER services. This amount is typical of the revenue ETSA Utilities earns each year from these services.

In commenting on the overall effectiveness of the form of regulation applied to excluded services during the 2000-05 regulatory control period, ESCOSA noted:

> Although the Commission has not been overwhelmed by a large number of disputes on excluded distribution services, street lighting (which forms over 60% of the total revenue generated by excluded distribution services) has been an issue of continuous contention.[92]

In explaining why it chose to classify SLUOS services as excluded services, ESCOSA noted:

> The Commission believes there is minimal scope for effective competition in the provision of SLUOS in the next regulatory period and, therefore, it had initially contemplated making SLUOS a prescribed distribution service. However two of the major customers of SLUOS services, local councils (represented by the Local Government Association of SA (LGA)) and Transport SA, have indicated in a joint submission their preference for SLUOS to remain an excluded service. One of the primary reasons for this suggestion is the view that both of these customers possess significant bargaining power, which they believe can be used to negotiate a competitive outcome for the provision of public lighting services. In light of this, the Commission would support a process of negotiation between the parties.[93]

Given the representations made by the LGA and Transport SA about their countervailing market power in the last determination, the AER is inclined to retain

[92] ESCOSA, *Prescribed and excluded distribution services – working conclusions,* June 2004, p.17.
[93] ESCOSA, *Prescribed and excluded distribution services – working conclusions,* June 2004, p.27.

SLUOS services under a negotiate-arbitrate framework and classify these services as negotiated distribution services.

The AER also understands that ESCOSA is currently considering a claim, submitted by several councils and the Minister for Transport, on the fairness and reasonableness of SLUOS charges. The resolution process is at a very early stage and the outcome from this process is not yet known. Depending on the timeframe of this process, it may be desirable to consider the outcome from this process in determining the service classification and form of regulation for SLUOS services in the next regulatory control period.

AER's preliminary position

The AER's preliminary position is to:

- classify CLER services as negotiated distribution services. Alternative options, including not classifying these services and removing them from the operation of the NER, will be considered in response to submissions.
- classify SLUOS services as negotiated distribution services. Alternative options will be considered in response to submissions and in light of progress on the current claim before ESCOSA.

2.4.3.5 Other distribution services

Whilst the services already addressed in this chapter constitute the majority of ETSA Utilities' revenue from distribution services, ETSA Utilities provides many more distribution services, of varying significance in terms of revenue and customer numbers.

Current classifications

ESCOSA classified a number of services, other than those already discussed, as excluded services. These services include:

- asset relocations
- disconnections and reconnections
- recoverable asset repairs
- high load escorts
- pole and duct rental, and
- feeder standby services.[94]

[94] ESCOSA, *2005-2010 electricity distribution price determination – part B – price determination*, April 2005, pp.35-37. Other services in this sense includes those services in schedule one of the EDPD under the headings of 'stand-by and temporary supply', 'distribution system', 'Electricity Distribution and Electricity Metering Codes', 'embedded generation', and 'other services'. It does not include retailer of last resort services, which are discussed in section 2.4.5 of this paper.

Issues and AER's considerations

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, the classification should be consistent with the previously applicable regulatory approach. As noted above, the effect of this presumption in relation to distribution services currently classified as excluded services, such as those above, is that they should be classified as negotiated distribution services under chapter 6 of the NER, so that the current regulatory approach (negotiate-arbitrate) is maintained.

The AER does not consider that pole and duct rental for non-electricity purposes, such as telecommunications purposes, falls within the NER definition of distribution services. This means that they can not be classified for the purposes of, or covered by, the economic regulatory framework in chapter 6 of the NER or the AER's distribution determination for ETSA Utilities. The AER notes that whilst these services, which would typically involve broadband providers paying the DNSP for access to install coaxial and fibre optic cables along the poles that comprise the distribution system, are not regulated under the NER, they are regulated under another regulatory framework. Holders of Carrier Licences, such as ETSA Utilities, are required under the *Telecommunications Act 1997* to provide access to other carriers if requested.[95] The terms and conditions of access are governed by the *Telecommunications Act 1997*.

Whilst some of the remaining services may be contestable and able to be provided by alternative providers, for many of these services it is likely that ETSA Utilities would be the dominant provider.

Due to the economies of scale and scope, which present a barrier to entry for alternative providers, and the interdependencies between these and the more core distribution services provided by ETSA Utilities, it would be expected that ETSA Utilities, as the incumbent DNSP, would generally possess some market power in providing these services.[96] However the less significant nature of many of these services may warrant a less intrusive regulatory approach than for the core distribution services, which leads the AER to conclude that a negotiated distribution services classification is more appropriate. The elasticity of demand for, and the substitutable nature of, some of these services may also be greater than for core distribution services, enabling customers with some countervailing market power.[97]

The AER acknowledges that Energex and Ergon Energy have recently proposed to the AER that some of these specific services, for example, high load escorts, are not distribution services and therefore should not be classified.[98] The AER's preliminary position is that these services appear to be provided in connection with the distribution system, and therefore would fall under the definition of distribution services under the NER. However, the AER will consider this issue further in

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[95] Telecommunications Act 1997, sch. 1, cl. 17(1).
[96] NER, cl. 6.2.1(c)(1).
[97] NER, cl. 6.2.1(c)(1).
[98] Energex, *Services classification and control mechanisms for distribution services – proposal to the Australian Energy Regulator under clause 11.16.6 of the National Electricity Rules*, March 2006, pp.97-98. Ergon Energy, *Proposal: services classification and control mechanism*, 31 March 2008, pp.87-88.

response to submissions on the South Australian and Queensland framework and approach processes.

AER's preliminary position

The AER's preliminary position is that, with the exception of pole and duct rental, which does not fall within the definition of a distribution service under the NER, ETSA Utilities' other distribution services should be classified in a manner which is consistent with the previously applicable regulatory approach, as no other classification is clearly more appropriate.

On that basis, these services should be classified as negotiated distribution services, which is consistent with the previously applicable regulatory approach. In response to submissions the AER will consider whether it is more appropriate not to classify any of these individual services (thereby excluding them from economic regulation under the NER). The AER will also consider further whether all of these services can, or should, be classified under the NER.

2.4.4 Step 2 – Division of direct control services into standard control and alternative control services

As stated, the presumption is that ETSA Utilities prescribed distribution services will become direct control services, and will be further classified as standard control services. ETSA Utilities' current prescribed services are summarised in table 2.1 above, and detailed in appendix A.

This section analyses whether a classification as alternative control services is clearly more appropriate for any of these services.

2.4.4.1 Issues and AER's considerations

Of the six factors the AER must have regard to in classifying direct control services between standard and alternative control services, three of these factors are the same as those the AER must have regard to in classifying distribution services. A fourth factor:

> the potential for development of competition in the relevant market and how the classification might influence that potential[99]

is similar to the form of regulation factors the AER must have regard to in classifying distribution services. Both involve a market power assessment.

Two additional factors are unique to this second step of classification, being:

> the possible effects of the classification on administrative costs of the AER, the Distribution Network Service Provider and users or potential users, [and]
>
> the extent the costs of providing the relevant service are directly attributable to the customer to whom the service is provided.[100]

[99] NER, cl. 6.2.2(c)(1).

[100] NER, cll. 6.2.2(c)(2) and 6.2.2(c)(5). Whilst these factors are unique to the classification step 2 in that they are explicitly listed for this step and not step 1, the AER could, if relevant, consider these factors in relation to classification step 1 under the banner of 'any other relevant factor'.

The AER considers that distribution services provided by ETSA Utilities for which the potential for development of competition may exist, and where the costs of providing a service may be directly attributable to the customer to whom the service is provided, have already been classified as negotiated distribution services under the AER's preliminary position in section 2.4.3 above.[101]

The AER does not consider that regard to administrative costs would warrant the classification of any direct control services as an alternative control service in this instance.[102]

2.4.4.2 AER's preliminary position

The AER's preliminary position is that ETSA Utilities' current prescribed distribution services should be classified in a manner which is consistent with the previously applicable regulatory approach as no other classification is clearly more appropriate.

On this basis, ETSA Utilities' current prescribed distribution services should be classified as direct control services, and further as standard control services. The AER's preliminary position is that none of these services should be classified as alternative control services.

2.4.5 Retailer of last resort services

ETSA Utilities is the retailer of last resort in South Australia. The retailer of last resort (ROLR) is responsible for assuming the obligations under the NER (including the obligation to pay trading amounts and other amounts due under the NER) of a market customer that has defaulted in the performance of its duties under the NER.[103]

In the current determination, ESCOSA classified services associated with the establishment of ROLR capabilities as prescribed distribution services and included an allowance for these services in ETSA Utilities' regulated revenue. A pass-through event was also included whereby ETSA Utilities could pass-through ROLR establishment costs if these costs were materially different to the allowance in the determination.

The ROLR provision services, that is, services provided to affected customers should a ROLR event actually occur, were classified as excluded services. Any shortfall between the excluded services charge and the costs of an actual ROLR event could also be claimed as a pass through by ETSA Utilities.

ETSA Utilities' current obligation to be the South Australian ROLR expires on 30 June 2010, which is the end of the current regulatory control period.[104] It is not yet known whether ETSA Utilities will be required to retain its role as the ROLR in the forthcoming regulatory control period.

Given this uncertainty, the AER's preliminary position is to defer consideration of the appropriate ROLR regulatory arrangements until it is clear whether or not ETSA Utilities' role as the South Australian ROLR will continue.

[101] NER, cl. 6.2.2(c)(1) and 6.2.2(c)(5).
[102] NER, cl. 6.2.2(c)(2).
[103] NER, chapter 10.
[104] *Electricity Act (South Australia) 1996*, section 23(3).

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); and
- if there has been no previous classification – the classification should be consistent with the previously applicable regulatory approach.[105]

When regard is had to the regulatory approach applicable to distribution services provided by ETSA Utilities in the current regulatory period[106], this gives rise to an implicit presumption that, in the forthcoming regulatory control period, ETSA Utilities' prescribed distribution services will be classified as direct control services, and further classified as standard control services, and ETSA Utilities excluded services will be classified as negotiated distribution services, unless a different classification is clearly more appropriate.

The AER's preliminary position is that, in the context of the presumption set out above, the current classifications are consistent with the requirements of cll. 6.2.1 and 6.2.2 of the NER, and that no different classification is clearly more appropriate.

In reaching this position on the classification of distribution services, the AER has had regard to the factors under cl. 6.2.1 of the NER which include a market power assessment embodied in the form of regulation factors. Having regard to this assessment, along with the other factors under cl. 6.2.1 leads the AER to classify some services as direct control services and other services as negotiated distribution services.

In reaching the position on the classification of direct control services, which is to classify all direct control services as standard control services, the AER has had regard to the factors under cl. 6.2.2 of the NER. The AER considers that under its preliminary position on the division of distribution services, all services for which the potential for the development of competition in a relevant market exists, and where the costs of providing the relevant service are directly attributable to the customer to whom the service is provided, will already be classified as negotiated distribution services.

The NER require the AER, in classifying distribution services, to have regard to the desirability of consistency in the regulatory approach and form of regulation within and beyond NEM jurisdictions. The preliminary positions set out in this chapter achieve consistency in the treatment of like services within South Australia. Due to the presumption in favour of the prior approach, consistency in the classification of similar services across the jurisdictions in the first round of regulatory determinations by the AER may not be possible, however, greater consistency would be seen as a medium to long term objective. That said, the AER may still apply different classifications for similar services across jurisdictions, even in the long term, due to

[105] NER, cll. 6.2.1(d) and 6.2.2(d)
[106] NER, cll. 6.2.1(c)(2) and 6.2.2(c)(3)

differences in relevant circumstances, for example, different legislative barriers to contestability that apply to similar services across jurisdictions.

The AER has considered the cost implications of the transition to a new framework in chapter 6, 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 previous classification, the AER is satisfied that the preliminary position set out in this paper provides for a smooth transition to the benefit of both ETSA Utilities and users, and does not impose unnecessary costs.

The AER's preliminary position on its likely approach to the classification of distribution services provided by ETSA Utilities is set out in the tables below.

Table 2.4 – AER's preliminary positions – ETSA Utilities' direct control and negotiated distribution services

Service category	Direct control	Negotiated distribution
Network services	Network services at mandated standard	Network services at higher than mandated standard
Connection services	Connection services at mandated standard	Connection services at higher than mandated standard New or upgraded connection services (o the extent the user is required to make a financial contribution)
Metering services	Small customer standard meter provision and energy data services excluding special meter reads (type 6 -7 metering installations)	Small customer non-standard meter provision and energy data services (type 1-5 metering installations) Small customer special meter reads (including monthly reads) Large customer meter provision and energy data services
Public lighting services	Nil	Operation and maintenance Provision of assets, operation and maintenance 'Energy only' service
Other services	Nil	Provision of stand-by or temporary supply Asset relocations Disconnections and reconnections Recoverable asset repairs High load escorts Feeder standby service

Source: AER analysis

As discussed in section 2.4.2.2, the AER has removed the ‘flexibility clause’, which currently allows the regulator to classify additional services as excluded services (negotiated distribution services) during the regulatory control period, as this approach is not permitted under the NER.

Table 2.5 – AER’s preliminary position – ETSA’s Utilities’ standard control and alternative control services

Service category	Standard control	Alternative control
Network services	All direct control network services	Nil
Connection services	All direct control connection services	Nil
Metering services	All direct control metering services	Nil
Public lighting services	Nil	Nil
Other services	Nil	Nil

Source: AER analysis

The AER considers that these classifications are likely to cover the full spectrum of distribution services. Accordingly, there are no distribution services that the AER has chosen not to classify. As noted in section 2.4.3.5 above, pole and duct rental for telecommunications purposes do not fall within the NER definition of distribution services, and can not be classified under chapter 6 of the NER. These services are therefore outside the scope of the economic regulatory framework for distribution services in chapter 6 and the AER’s distribution determination for ETSA Utilities.

3 Form of control mechanisms

3.1 Introduction

This chapter sets out the AER's draft position on the form or forms of control to be applied to ETSA Utilities' direct control services for the forthcoming regulatory control period. Direct control services consist of standard control services and alternative control services. Different forms of control 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 six of the NER.

The AER's preliminary position on its likely approach to the classification of ETSA Utilities' services is discussed in chapter two of this paper.

3.2 Requirements of the National Electricity Law and Rules

A distribution determination imposes controls over the prices of direct control services, the revenue to be derived from direct control services, or both.[107] The AER's framework and approach paper must state the form or forms of 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.[108]

Unlike other elements of the framework and approach paper, the AER's statement of the form or forms of control in the framework and approach paper is binding on the AER and the DNSP for the relevant distribution determination: the control mechanisms in the distribution determination must be as set out in the framework and approach paper.[109]

3.2.1 Available control mechanisms

The NER limits 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[110]
- the basis of the control mechanism.[111]

The available options for the *form* of control are:

- a schedule of fixed prices

[107] NER, cl. 6.2.5(a)
[108] NER, cl. 6.8.1(c)
[109] NER, cl. 6.12.3(c)
[110] NER, cl. 6.2.5(b)
[111] NER, cl. 6.2.6(a)

- 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 (i.e. an average revenue cap), or
- a combination of any of the above.[112]

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 in relation to standard control and alternative control services.

3.2.2 Standard control services

In deciding on a control mechanism for standard control services, the AER must have regard to:

- 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), and
- any other relevant factor.[113]

The basis for the control mechanism for standard control services must be of the prospective CPI minus X (CPI-X) form or some incentive-based variant of the CPI-X form in accordance with part C of chapter six of the NER.[114]

3.2.3 Alternative control services

The factors the AER must have regard to in deciding on a control mechanism for alternative control services are the same as those for standard control services in all but one respect. Whereas for standard control services the AER must have regard to the need for efficient tariff structures, for alternative control services the AER must instead have regard to the potential for development of competition in the relevant market, and how the control mechanism might influence that potential.[115]

The control mechanism must have a basis specified in the distribution determination.[116] This may, but need not, utilise elements of chapter six, Part C, and if it does may do so with or without modification. For example, the control mechanism

[112] NER, cl. 6.2.5(b)
[113] NER, cl. 6.2.5(c)
[114] NER, cl. 6.2.6(a)
[115] NER, cl. 6.2.5(d)
[116] NER, cl. 6.2.6(b)

may (but need not) use a building block approach, and may (but need not) incorporate a pass-through mechanism.[117]

3.2.4 Requirements specific to South Australia

3.2.4.1 Electricity Pricing Order

The *National Electricity (South Australia) Act 1996* contains a number of provisions governing the transfer of economic regulation of electricity distribution to the AER. Under these provisions, the AER must give effect to the provisions of the Electricity Pricing Order (EPO) made by the South Australian Treasurer on 11 October 1999.[118] While most provisions relating to ETSA Utilities ceased on 30 June 2005 (i.e. the end of ETSA Utilities' first regulatory control period), the EPO contains certain provisions that are to apply during future regulatory periods, including ETSA Utilities' forthcoming regulatory control period. These provisions of the EPO will be taken to continue to apply as if the AER were the regulator under the EPO.[119]

Of relevance to the control mechanism, the EPO contains provisions regarding ETSA Utilities' recovery of costs relating to programs for the undergrounding of powerlines that are at the direction of the Minister. Clause 7.3(c) of the EPO states:

> (c) if ETSA Utilities is required to undertake work in accordance with a program for the undergrounding of powerlines established by the Minister under the [*Electricity Act (SA) 1996*], treat the costs of undergrounding as follows:
>
> …
>
> (ii) in respect of undergrounding that occurs during the regulatory period for which the price determination is being made:
>
> (A) in determining the aggregate revenue in each year after the year in which the undergrounding occurs, if any undergrounding is required in excess of that for which an allowance has already been made in making the price determination, an amount must be included to reflect a return on the new underground assets and the recovery of their depreciation, based on a valuation of the assets at the efficient cost of undergrounding (and not at the cost of installing overhead lines) and the expected average life of the assets, and
>
> (B) in determining the aggregate revenue in the year after overhead poles and wires removed as a result of the undergrounding are removed from the asset register, an amount must be included to reflect the written down value of the overhead line and poles removed.

The control mechanism applied by the AER in its distribution determination for ETSA Utilities must have regard to this treatment of the specified costs.

[117] NER, cl. 6.2.6(c).
[118] *National Electricity (South Australia) Act 1996*, s. 18(4)
[119] *National Electricity (South Australia) Act 1996*, s. 18(6).

3.2.4.2 Jurisdictional derogation for South Australia

In addition to the EPO provisions preserved in the *National Electricity (South Australia) Act 1996*, chapter nine of the NER sets outs derogations from the application of chapter 6 that are specific to the AER's distribution determination for ETSA Utilities for the regulatory control period commencing in 2010.

In particular:

- The AER's distribution determination must allow ETSA Utilities to carry forward impacts associated with the calculation of Maximum Average Distribution Revenue (MADR) under its 2005-2010 price determination into the 2010/11 and 2011/2012 regulatory years.[120]
- The following side constraint is to be applied to tariffs for small customers[121] for the regulatory control period to which the 2010 distribution determination applies:

> The fixed supply charge component of the tariff must not increase by more than $10 from one regulatory year to the next.[122]

- Any reduction in transmission network charges as a result of a regulatory reset (excluding reductions resulting from the distribution of settlements residue and settlement residue auction proceeds) must be paid to all customers.[123]

These requirements are relevant to the basis of control to be applied by the AER.

3.3 Form of control mechanism for standard control services – current regulatory arrangements

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 regulatory control period 2010-2015. The starting point for the AER's consideration is the control mechanism applied to the relevant services in the current regulatory control period, under the 2005-10 Electricity Distribution Pricing Determination (EDPD).

Sections 3.6.1 and 3.6.2 should be viewed on the basis that the AER's preliminary positions relating to the classification of ETSA Utilities' distribution services are adopted.

[120] NER, cl. 9.29.5(b)(2)
[121] Clause 9.29.5(a) states that in this clause 'small customer has the same meaning as in the *Electricity Act 1996(SA)*'. Section four of that Act states that 'small customer means a customer with an annual electricity consumption level less than the number of MWh per year specified by regulation for that purpose, or any customer classified by regulation as a small customer'. The *Electricity (General) Regulations 1997* (SA) define a small customer as one whose annual electricity consumption level for a connection point is less than 160 MWh (s. 4B).
[122] NER, cl. 9.29.5(d). In preparing its distribution determination for the following regulatory control period, the AER must consider whether this side constraint should continue with or without modification.
[123] NER, cl. 9.29.5(f)

3.3.1 Current regulatory arrangements for ETSA Utilities

In the current regulatory control period (and the EPO, which applied to the 2000-05 regulatory control period) ETSA Utilities’ prescribed services are subject to a variant of an average revenue cap.

Specifically, the forecast average distribution revenue (FADR) ETSA Utilities will recover through tariffs in any given year of the regulatory control period must not exceed the MADR allowed in the EDPD for that year.

The MADR is determined by the following formula:

$$MADR_t = \frac{\left[\sum_{j=1}^{J}\left(ADR_{t,j} \times FDE_{t,j}\right) - K_t - Q_t + SI_t + U_t - P_t\right]}{FDE_t} + EPO_t$$

The formula comprises both the form of control mechanism and basis of the control mechanism. Components relating to the form of control mechanism are:

- the average distribution revenue per tariff class ($ADR_{t,j}$)
- the total forecast quantity in year t (FDE_t) which is also defined according to tariff class j in year t ($FDE_{t,j}$)
- the total revenue for each tariff class $\sum_{j=1}^{J}\left(ADR_{t,j} \times FDE_{t,j}\right)$
- an average revenue adjustment to reconcile differences between actual and forecast average revenue (K_t).

Components relating to the basis of the control mechanism are:

- a forecast quantities collar (with a 85 per cent penalty or bonus on revenue) which is applied according to respective tariff classes (Q_t)
- a service incentive revenue allowance (SI_t)
- an undergrounding allowance (U_t)
- a revenue adjustment arising from the provision of excluded and unregulated services using prescribed distribution infrastructure (P_t)
- an adjustment for a carryover of adjustments made in the EPO (EPO_t), and
- a tariff rebalancing control or side constraint (where distribution tariff components cannot increase by more than CPI+3.5% in the following year) (not separately shown in the equation above).

Implicit in this formula is a cost pass-through mechanism. The EDPD notes that the effect of the pass-through mechanism is that tariffs are permitted to be adjusted should specified events occur which move ETSA Utilities’ costs away from those when the controls were set, so that ETSA Utilities is placed in the same position as it would have been 'but for' the occurrence of that event.[124]

3.3.1.1 EDPD form of control

The form of control mechanism as defined in the EDPD operates as follows. Each year ETSA Utilities is required to allocate its total electricity distributed into ten separate 'distribution tariff classes' (measured by MWh). Each of these distribution tariff classes is assigned an allowed average revenue per MWh (in $/MWh). The maximum allowed revenue in any given year is then computed by multiplying the allowed average revenue in each distribution tariff class ($/MWh) by the electricity actually distributed (in MWh) to that tariff class.

The allowed average distribution revenue in each tariff class is allowed to evolve slowly over time – by an amount equal to CPI-X (in the 2005-2010 EDPD, X is set to -0.8%).

The out-turn revenue earned by ETSA Utilities, and the out-turn electricity distributed to each tariff class, are only observed after the end of each regulatory year. As a result, there is a need for an 'unders and overs' mechanism (the K factor in the EDPD) which adjusts the revenue in a subsequent year for both (a) any upward or downward adjustments in the MADR in any one year (due to variation in the electricity distributed from that forecast); and (b) any under or over recovery of the actual revenue relative to the MADR.

The details of the form of control currently applied to ETSA Utilities are set out in schedule three of Part B the 2005-10 EDPD.

In effect, putting aside the adjustments set out in the following section, the basic 'average revenue cap' form of control applied to ETSA Utilities ensures that the MADR that ETSA Utilities is allowed to earn in any one year is equal to the sum, for each of ten tariff classes, of the electricity distributed to that tariff class times the average revenue allowed to that tariff class.

3.3.1.2 Adjustments to the control mechanism

The 2005-10 EDPD provides for a series of annual adjustments to the revenue calculation.

These adjustments have been used either to provide further incentives to ETSA Utilities, to mitigate risks or to ensure the integrity of the EPO.

Reducing the dependence of allowed revenue on out-turn electricity volumes (Q_t)

Under a simple average revenue cap, the allowed revenue in each tariff class would be simply proportional to the electricity volume distributed in each tariff class. This can create undesirable incentives in terms of volume forecasts and can also expose the DNSP to volume risk. To mitigate these effects, the 2005-10 EDPD puts in place an adjustment factor which increases the MADR when out-turn volumes are below a forecast level, and which reduces the MADR when out-turn volumes exceed a forecast level.

[124] ESCOSA, *2005-2010 Electricity Price Determination: Part A – Statement of Reasons*, Final Decision – Statement of Reasons, April 2005, p. 195.

Specifically, if the actual quantity for a tariff class is above the forecast by more than 0.5 per cent in a given year, the MADR is reduced by a percentage (85 per cent) of the additional revenues earned from the excess volumes. Conversely, if the actual volume of electricity distributed to a tariff class falls below the forecast amount by 0.5 per cent in a given year, the MADR for that year is increased by 85 per cent of the shortfall in volume.

In effect, if out-turn volumes in a tariff class exceed a forecast level by more than 0.5 percent, or fall short of the forecast level by more than 0.5 per cent, the allowed revenue on any additional sales is reduced to just 15 per cent of the average revenue allowed to that tariff class.

The effect of this adjustment is to significantly reduce the sensitivity of the allowed revenue to out-turn electricity volumes and thereby to bring this form of control much closer to a "revenue cap" – the mechanism would be identical to a revenue cap if the sharing ratio were reduced from 15 per cent to zero per cent, and if the volume threshold for triggering the sharing arrangements were reduced from 0.5 per cent to zero per cent.

Service incentive allowance (SI_t)

This is a bonus or penalty given to ETSA Utilities for maintaining service standards in accordance with the incentive mechanism in the 2005-10 EDPD. If ETSA Utilities meets its performance targets (individually calculated for various measures) it receives an increase to its MADR. Where targets are not met, MADR is reduced.

Undergrounding allowance (U_t)

The EPO required recognition, in the calculation of ETSA Utilities aggregate revenue, of the costs associated with undergrounding of powerlines as required by the Power Line Environment Committee (PLEC). If, within any year of the regulatory control period, undergrounding is required for which no allowance was made in the EDPD, an adjustment must be made to reflect:

- in each year after the year in which the undergrounding occurs, a return on the new underground assets and the recovery of their depreciation, based on a valuation of the assets at the efficient cost of undergrounding and the expected average life of the assets, and
- in the year after overhead poles and wires removed as a result of the undergrounding are removed from the asset register, the written down value of the overhead lines and poles removed.[125]

Profit sharing mechanism (P_t)

In the 2005-10 EDPD, ESCOSA introduced a profit sharing mechanism (the P-factor), whereby 40 per cent of ETSA Utilities' pre-tax annual profits from non-prescribed services (i.e. excluded and unregulated services) that were provided using the regulated asset base would be shared with prescribed service customers. [126] The P-factor operates as a lagged adjustment (reduction) to the MADR based on the

[125] *Electricity Pricing Order*, 11 October 1999, cl. 7.2(f)

[126] ESCOSA, *2005 - 2010 Draft Electricity Distribution Price Determination Part A Statement of Reasons*, April 2005, pp. 32-33.

estimated profits from the previous year. This amount is adjusted in the subsequent year when the actual profits are known.

This was the first scheme of this nature to be introduced in Australia. The P-factor represents a proxy for cost allocation between prescribed and other services, as certain costs are effectively allocated away from the prescribed distribution business.

ESCOSA decided to use a profit sharing mechanism instead of revenue sharing mechanism to lower the risk to ETSA. Under a revenue sharing mechanism, even if the non-prescribed distribution business was not making a profit it would be required to pass back benefits to the prescribed distribution business, whereas under a profit sharing mechanism these benefits only pass back if the non-prescribed distribution business makes a profit. ESCOSA considered that the scheme would provide an equitable reflection of the use of regulated assets while not imposing additional risk on ETSA in providing non-prescribed services. [127]

EPO carryover mechanism (EPO_t)

A number of adjustment factors in the 2000-05 EPO applied for two years subsequent to the regulatory year on which the adjustment was calculated. These adjustments were carried forward to the 2005-10 EDPD to ensure the integrity of the EPO was retained.

3.4 Form of control mechanism for standard control services – AER's preliminary position

The current control mechanism for prescribed services for ETSA Utilities is a variant of an average revenue cap (revenue yield). The basis of the control mechanism is a variant of CPI-X. Subject to the factors to which the AER must have regard in selecting a control mechanism for standard control services, the current control mechanism is available to the AER under cll. 6.2.5(b) and 6.2.6(a) of the NER.

As discussed in section 3.3.1, the 2005-10 EDPD provides for a series of annual adjustments to the revenue calculation for items such as:

- the undergrounding allowance (U_t)
- the revenue adjustment by tariff class (Q_t)
- the service incentive scheme (SI_t)
- the profit sharing mechanism (P_t) and
- the EPO carryover mechanism (EPO_t).

The AER considers that these adjustments are incentive-based variants of the prospective CPI-X form, of the nature contemplated by cl. 6.2.6(a).

The AER's preliminary positions on the merits of retaining the current form of control and these adjustments are considered in sections 3.4.1 and 3.4.2 below.

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[127] ESCOSA, *2005 - 2010 Draft Electricity Distribution Price Determination Part A Statement of Reasons*, April 2005, p. 32.

3.4.1 AER's preliminary position on the form of control for standard control services

The suitability of the current form of control for standard (formerly prescribed) services in the context of the NER requirements outlined in section 3.2 of this paper, is considered below.

3.4.1.1 The regulatory arrangements applicable in the current regulatory period

Given the presence of the Q factor adjustment to the average revenue cap, the AER considers the form of control is a combination of an average revenue cap and a revenue cap. In considering the form of control that will apply to ETSA Utilities' standard control services in the forthcoming regulatory control period, the AER has taken as its starting point the regulatory arrangements, including the form of control, applicable to those services in the current regulatory period.[128]

3.4.1.2 Incentives and risks

In deciding on a form of control for standard control services, the NER allow the AER consider any factor it considers relevant.[129] The AER considers that both the incentive and risk properties generated by specific control mechanisms are important considerations in this respect.

The AER recognises that average revenue caps can have undesirable properties such as:

- creating incentives on the DNSP to set prices which increase usage of electricity, which can undermine efficient demand management practices
- creating incentives to increase connections to high-volume users, while reducing connections to low-volume customers (although the variant of the average revenue cap set out in the 2005-10 EDPD offsets this incentive by setting a lower average revenue allowance on tariff classes relating to higher-volume customers)
- creating incentives to game forecasts of electricity sales (and, in particular, to under-forecast future electricity sales in each tariff class) and
- exposing the DNSP to volume risks when electricity sales volumes fall below forecast levels (making it difficult for the DNSP to recover its costs).

These incentive and risk properties arise because of the discrepancy that arises under an average revenue cap between a DNSP's revenue and costs. Under an average revenue cap, the DNSP's revenue increases with volumes of electricity sales. In contrast, the costs of providing a distribution network are virtually entirely independent of electricity volumes and depend, rather, on factors such as the number of customers and the peak capacity that electricity can be delivered to each customer.

In its final EDPD, ESCOSA notes:

> Over the 2000-2005 regulatory period, ETSA Utilities' actual sales have tended to be below those forecast under the EPO, particularly over the latter parts of the regulatory period. This is due predominantly to the impact of

[128] NER, cl. 6.2.5(c)(3)
[129] NER, cl. 6.2.5(c)(5)

> weather on actual sales and to the retail price increases experienced at the commencement of retail contestability…
>
> …There is also conflict between the incentives generated under average revenue regulation and the demand management initiatives that have been supported in this Price Determination (see Chapter 4). Indeed, the average revenue controls required to be adopted under the EPO might not be in the long term interests of consumers.[130]

In order to address these dual issues ESCOSA included the Q factor (Q_t) adjustment in its control mechanism. The Q factor adjustment in the current form of control materially reduces, but does not eliminate, the sensitivity of revenue to out-turn electricity sales volumes.

Under certain conditions, this adjustment mechanism has the potential to create undesirable outcomes such as price shocks. This problem is considered in section 3.4.2.1 of this paper.

The AER's preliminary position is that the potential impacts on incentives and risk that may arise under the existing form of control can be adequately addressed through application of appropriate adjustment mechanisms, such as the Q factor, and that departure from the current form of control is not required on that basis. The nature and values that apply to adjustment mechanisms are considered in sections 3.4.2, and in the context of the incentive schemes discussed in chapters 4 and 6 of this paper.

3.4.1.3 The need for efficient prices

ESCOSA noted in its statement of reasons for the draft EDPD that the proposed form of control ensures 'that prices are reflective of the different costs of supplying certain types of customers.'[131] The AER understands that ESCOSA was required to maintain an average revenue cap as a requirement of the EPO and therefore included average revenue caps according to tariff classes. The AER considers that under the current form of control mechanism there has been an attempt to connect the prices charged to costs attributed to particular groups of customers and the average revenue allowed to a particular tariff class. This can be demonstrated by the following table in Part B of the 2005-2010 EDPD:

[130] ESCOSA, *2005 - 2010 Electricity Distribution Price Determination Part A Statement of Reasons*, April 2005, pp. 186-187.
[131] ESCOSA, *Draft 2005-2010 Electricity Distribution Price Determination Part A Statement of Reasons*, November 2004, p. 201.

Table 3.1: Average Distribution Revenue by Tariff Class

Distribution Tariff Class $_J$	**ADR($/MWh)**
Sub transmission	3.43
Zone substation	8.42
High voltage / High voltage (obsolete)	21.21
Low voltage demand	29.67
Low voltage business - 2 rate	48.01
Low voltage business - single rate	64.09
Low voltage residential - single rate	69.72
Low voltage off-peak controlled load	14.99
Low voltage unmetered usage (overnight)	31.73
Low voltage unmetered usage (24 hour)	35.52

Source: 2005-2010 EDPD Part B, *Average Distribution Revenue*, p. 42

The AER notes that the tariff classes which use the distribution network more (for example lower voltage residential customers) were assigned a higher average revenue cap while tariff classes which use the distribution network less (for example sub transmission) were assigned a lower cap.

However, the current form of control is unable to prohibit cross subsidisation and therefore there is no necessary connection between the prices charged to particular groups of customers and the average revenue allowed to a particular tariff class.

As noted above, the average revenue cap form of control creates no particular incentive to set prices efficiently. Indeed, it creates incentives for ETSA Utilities to set prices so as to encourage connections to ‘high yield’ customers (those customers which yield additional revenue – in the form of additional electricity sales – most in excess of the costs of service for those customers) and to discourage connections to ‘low yield’ customers. In addition, the average revenue cap form of control incentivises ETSA Utilities to increase electricity sales volumes and to resist demand management schemes. However, as noted in section 3.3.1.2 ESCOSA has addressed these concerns to a significant extent through the introduction of the Q factor.

This results in a form of control that more closely resembles a revenue cap and diminishes the undesirable incentives which are discussed above. The AER considers that the revenue cap has less undesirable incentives than the average revenue cap in these respects. However, the AER notes that under a revenue cap, the incentive is to reduce costs in order to maximise its return. The AER notes that these incentives are addressed through the implementation of adjustment mechanisms in the form of control and in the operating expenditure allowance.

The AER notes that section 18(5)(a) of the *National Electricity (South Australia) Act 1996* provides that:

(a) the AER must, in making a distribution determination or approving a pricing proposal for the purposes of the Rules, ensure that the prices charged to small customers for network services in relation to distribution services in the State are not subject to variation on the basis of location.

Under any form of control the AER must follow this requirement. The AER therefore considers that cost reflectivity of prices may not be completely achieved given the above clause. However, the AER notes that this does not limit its ability to approve tariffs based upon a number of different means (for example off-peak and peak tariffs).

The AER considers that in order for distribution prices to reflect costs and to be consistent with cl. 6.2.5(c)(1) of the NER that the prices charged to retailers would need to be passed on to the consumers. At this stage it is unclear to the AER whether this is likely to occur under any form of control.

3.4.1.4 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.

No single control mechanism is consistently applied to prescribed services (those most likely to be classified as standard control services under chapter 6) in the NEM. A weighted average price cap, average revenue cap and revenue cap (subject to minor variations) are each applied in two jurisdictions. The AER's preliminary position is that pursuit of consistency in forms of control between jurisdictions is a matter to be considered in the longer term, and that consistency between jurisdictions should not be a driving consideration in selection of forms of control at this time.

Going forward, the AER will give more detailed consideration to the desirability of applying common forms of control to standard control services provided by all DNSPs. Further analysis is expected to be conducted on this issue through a number of regulatory processes before the AER reaches a final position on this issue. Any such decision will be made with due regard to the reasons that different forms of control have been applied in particular jurisdictions to date.

The AER notes, however, that the form of control is consistently applied to similar services within each NEM jurisdiction. The AER considers this is desirable. For that reason the AER's preliminary position is that the application of a single form of control to standard control (formerly prescribed) services provided to ETSA Utilities should continue in the forthcoming regulatory control period.

3.4.1.5 Administrative costs

Clause 6.2.5(c)(2) 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 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 DNSPs.

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 the likely impact of any change in form of control from the current regulatory period to the next.

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. However the AER will consider other forms of control if it can be demonstrated that changing to another form of control will not impose administrative costs that outweigh the benefits of departure from the present arrangements.

3.4.2 AER's position on the basis of control for standard control services

As noted in section 3.4, the control mechanism applied to ETSA Utilities in the current regulatory control period includes a number of incentive-based variants of the CPI-X form of control. These annual adjustments, and the AER's preliminary position in relation to each, are discussed in turn below.

3.4.2.1 Reducing the dependence of allowed revenue on out-turn electricity volumes (Q_t)

The AER's preliminary position is that if the current control mechanism is to be retained, the Q factor adjustment in the current form of control should also be retained as it reduces, but does not eliminate, the sensitivity of revenue to out-turn electricity sales volumes.

However, this adjustment mechanism has the potential to create undesirable outcomes such as price shocks and other risks to the DNSP. This arises due to:

- the presence of the side constraint (where average distribution tariffs by tariff class cannot increase by the greater of CPI-X+2% and CPI+2% in the following year as required by the NER[132])
- tariffs are mainly comprised of throughput charges, and
- weather conditions when extreme weather (for example very hot summers or very cold winters) in one year is followed by milder than expected weather in the following year.

The combination of the above issues may result in the DNSP being unable to recover its lost revenue, as the side constraint limits the ability of a DNSP to increase the tariff for a given tariff class. Volatility in weather conditions from one year to the next may result in price shocks as the Q factor adjustment switches from positive to negative.

Another undesirable outcome that may arise with the presence of the Q factor, or a revenue cap, is volume risk arising from greater peak demand growth than originally

[132] NER, cl. 6.18.6(c).

contemplated in forecasts during the regulatory control period. Under these circumstances the DNSP is forced to augment the network more than was originally contemplated, which may result in costs approaching or exceeding the revenue cap. This can lead to a large increase in distribution tariffs in the subsequent control period when these assets are rolled into the regulated asset base and the costs for the additional augmentation are passed on to consumers. The AER considers that volume risks on both consumers and the DNSP arising from weather can be mitigated by setting appropriate Q factor parameters and the introduction of a smoothing mechanism.

The AER's preliminary position is that the current parameters of a collar of 0.5 per cent on actual quantities per tariff class and a sharing ratio of 15 per cent will be maintained. The AER also proposes that a Q-factor carryover mechanism be introduced to ensure that weather related volume risks for consumers and ETSA are mitigated. This will be on the basis that ETSA Utilities can demonstrate in its regulatory proposal that it is unable to recover lost revenues due to abnormal weather. The AER intends to adopt a similar approach to that described in the 2008-2012 GasNet Access Arrangement.[133] If the side constraint of CPI+2% on weighted average tariff classes means that ETSA Utilities is unable to recover the full amount of any shortfall under the Q-factor in the current regulatory control period, any unrecoverable Q will be carried over to next regulatory control period.

ETSA Utilities will be allowed to claim the revenue increment it was unable to recover from the application of the Q-factor component of the form of control (due to the side constraint) as a building block under cl. 6.4.3(a)(6) of the NER.[134] The amount of the revenue increment would be adjusted to ensure that the building block amount represents nominal dollars, and is spread uniformly across the next regulatory control period.

The AER considers that this approach, which will assist in mitigating risks faced by users and ETSA Utilities, satisfies the requirements of the NER.

3.4.2.2 Service target performance incentive scheme (S_t)

As discussed in chapter 4 of this paper, the AER's preliminary position is that the reliability of supply and customer service components of its STPIS (collectively 'the s-factor') will be applied to ETSA Utilities in the forthcoming regulatory control period. In application, this will take the form of an annual adjustment to revenue that is similar in nature to that applied in the current regulatory control period.

The AER's preliminary position is that such adjustments will take the form of a continued S_t adjustment in the first two years of the forthcoming period. This adjustment will be applied within the form of control as follows:

[133] ACCC, *Revised Access Arrangement by GasNet Australia (Operations) Pty Ltd and GasNet (NSW) Pty Ltd for the Principal Transmission System*, Final Decision, 30 April 2008, p. 112.

[134] Under 6.4.3(a)(6), building blocks include the other revenue increments or decrements (if any) for that year arising from the application of a control mechanism in the previous regulatory control period. The other revenue increments or decrements are those that are to be carried forward to the current regulatory control period as a result of the application of a control mechanism in the previous regulatory control period and are apportioned to the relevant year under the distribution determination for the current regulatory control period: cl 6.4.3(b)(6).

$$MADR_t = \left(\sum_{j=1}^{J} \left(ADR_{t,j} \times FDE_{t,j} \right) - K_t \right) \bullet \left(1 + S_t\right) - Q_t + U_t + EDPD_t$$

As noted in section 3.2, the AER's distribution determination must allow ETSA Utilities to carry forward impacts associated with the calculation of MADR under its 2005-10 price determination into the 2010/11 and 2011/2012 regulatory years.[135] This obligation extends to adjustments to apply rewards or penalties payable under ESCOSA's service incentive scheme. The AER's proposed approach to this requirement is discussed in section 3.4.2.6 below.

3.4.2.3 Profit sharing of negotiated and unregulated services (P_t)

The AER recognises that the profit sharing mechanism was implemented as a benefit sharing mechanism between users of shared infrastructure. However, in order for the profit sharing mechanism to be continued under chapter 6 of the NER, it must be demonstrated that some interdependence or interrelationship exists between the provision of direct control services and unregulated services, and that the interdependence makes it necessary to have regard to profits earned on unregulated services in order to constrain ETSA Utilities' market power in relation to direct control services (ie – by way of an adjustment to regulated revenue). The AER would also need to be satisfied that such an approach furthers the national electricity objective and NER requirements in relation to the economic regulation of direct control services.

The AER is not currently aware of any such interdependency, and does not consider it clear at this time that the current profit sharing mechanism furthers the national electricity objective and NER requirements in relation to the economic regulation of direct control services.

While it recognises ESCOSA's intention in introducing the profit sharing mechanism, the AER's preliminary position is that the NER do not allow the profit sharing mechanism to be included in the next regulatory control period, outside of the EDPD carryover mechanism. Transitional arrangements for South Australia under the NER require the AER to carry forward impacts of the 2005-10 EDPD to the first two years of the 2010-15 regulatory control period. The AER will therefore investigate means by which to identify and treat impacts of the application of the profit sharing mechanism in the current regulatory control period in those years. The proposed approach to this is discussed in section 3.4.2.6 below.

3.4.2.4 Undergrounding (U_t)

As noted in section 3.2.4.1 above, clause 7.3(c) of the EPO requires the AER to include in its distribution determination an adjustment for undergrounding in identical terms to that applied by ESCOSA in the 2005-10 EDPD.

The AER's preliminary position is that this requirement is appropriately met in the form of a U_t adjustment, as in the EDPD.

[135] NER, cl. 9.29.5(b)(2)

3.4.2.5 Other changes required by chapter 6 of the NER

Differences between the framework for economic regulation of standard control services in chapter 6 and that which governed the 2005-10 EDPD mean that a number of additional changes must be made to the control mechanism that will apply in the forthcoming regulatory control period. These include:

- use of a nominal post-tax weighted average cost of capital (WACC) instead of a pre-tax real WACC as required under the NER[136]
- removal of adjustments for inflation from the formula due to the use of a nominal WACC
- addition of an adjustment for the demand management incentive scheme (DMIS), as discussed in chapter 6 and
- addition of an explicit adjustment for cost pass through events.[137]

The AER also notes that the side constraint of the greater of CPI-X+2% and CPI+2% to be applied to the weighted average price for a tariff class under cl. 6.18.6(c) of the NER varies from the ESCOSA decision of CPI+3.5%. In the forthcoming regulatory period, the side constraint on prices will be changed in order to be comply with the NER.

3.4.2.6 Changes required by chapter 9 of the NER

As noted in section 3.2.4.2 above, cl. 9.29.5(b)(2) of the NER requires the AER's distribution determination for the forthcoming regulatory control period to allow ETSA Utilities to carry forward impacts associated with the calculation of MADR under its 2005-2010 price determination into the 2010/11 and 2011/2012 regulatory years.

In order to maintain the integrity of the EPO, an adjustment factor was included in the control mechanism in ESCOSA's 2005-10 EDPD. The AER's preliminary position is that compliance with cl. 9.29.5(b)(2) is best achieved through a similar adjustment factor ($EDPD_t$) to ensure the integrity of the adjustments in the current control formula. This factor will carry forward impacts associated with the calculation of MADR under its 2005-2010 price determination into the 2010/11 and 2011/2012 regulatory years.

As noted in section 3.2.4.2 above, cl. 9.29.5(d) of the NER requires that the fixed supply charge component of the tariff for small customers must not increase by more than $10 from one regulatory year to the next during the regulatory control period. The EDPD supply charge constraint for small customers is currently that it must not increase by more than $5 from one regulatory year to the next. The AER's preliminary position is that compliance with cl. 9.29.5(d) is best achieved through changing the side constraint to the supply charge for small customers as defined in the derogation.

[136] NER, cl. 6.5.2(b)

[137] Although cost passthroughs have not been explicitly included as an adjustment factor by ESCOSA in previous periods, pass-through amounts have been given to ETSA Utilities in the past.

3.4.2.7 Proposed control formulae for standard control services

Given the regulatory requirements and the AER's preliminary position on the form and adjustments to the form of control, the AER proposes the following control formulae:

$$FADR_t \leq MADR_t$$

$$FADR_t = FDR_t$$

$$MADR_t = \left(\sum_{j=1}^{J} \left(ADR_{t,j} \times FDE_{t,j} \right) - K_t \right) \bullet \left(1 + S_t \right) - Q_t + U_t + EDPD_t$$

The formula comprises both the form of control mechanism and basis of the control mechanism. Components relating to the form of control mechanism are:

- the average distribution revenue per tariff class $j(ADR_{t,j})$
- the forecast/actual distribution revenue in year t (FDR_t)
- the total forecast quantity in year t by tariff class j ($FDE_{t,j}$)
- the total revenue for each tariff class $\sum_{j=1}^{J} \left(ADR_{t,j} \times FDE_{t,j} \right)$
- an average revenue adjustment to reconcile differences between actual and forecast average revenue (K_t), as defined in the 2005-2010 EDPD Part B.

Components relating to the basis of the control mechanism are:

- a forecast quantities collar (0.5 per cent below or above the forecast amount with a 85 per cent penalty or bonus on revenue respectively) which is applied according to respective tariff classes (Q_t)), as defined in the 2005-2010 EDPD Part B
- a service target performance incentive scheme adjustment (S_t)), as defined in chapter 4
- an undergrounding allowance (U_t)), as defined in the 2005-2010 EDPD Part B
- an adjustment for a carryover of adjustments made in the 2005-2010 EDPD ($EDPD_t$), comprising the previous K, Q, P, U and SI factor adjustments
- a tariff rebalancing control or side constraint (where average distribution tariffs by tariff class cannot increase by more than the greater of CPI-X+2% and CPI+2% in the following year)
- a side constraint placed on the fixed supply charge component where the tariff must not increase by more than $10 from one regulatory year to the next, and
- adjustments to operating and capital expenditure for:
    - the EBSS that applied under the 2005-2010 EDPD
    - the AER's proposed EBSS, as discussed in chapter 5
    - the DMIS allowance, as discussed in chapter 6 and

- any Q-factor carryovers due to weather volatility, as discussed in section 3.4.2.1.

3.5 Form of control mechanism for alternative control services

The AER's framework and approach paper must state the form(s) of control mechanism(s) that will apply to alternative control services during the regulatory control period 2010-2015.

3.5.1 Current regulatory arrangements for ETSA Utilities

As discussed in chapter 2, in the current regulatory control period access to ETSA Utilities' non-prescribed, or excluded services was determined under a negotiate/arbitrate framework rather than by a direct control on revenue and/or prices.

3.5.2 AER's preliminary position on form of control for alternative control services

For the reasons set out in chapter 2, the AER's preliminary position is that none of the distribution services provided by ETSA Utilities will be classified as alternative control services in the forthcoming regulatory control period. It is therefore unnecessary to identify a control mechanism for such services at this time.

Should stakeholders consider that particular services provided by ETSA Utilities are, with regard to the factors set out in chapter 2, appropriately classified as alternative control services, the AER would be interested in any submissions to that effect, including recommendations on the control mechanism that should be applied. Any decision on this matter will be made with regard to the NER requirements set out in section 3.2 of this chapter. Submissions of this nature should therefore take into account the requirements of cl. 6.2.5 of the NER.

3.6 AER's preliminary position on form of control mechanisms

3.6.1 Standard control services

The AER's preliminary position is that, subject to minor adjustments to address issues identified in the course of its preliminary assessment, the form of control applied by ESCOSA to prescribed services in the current regulatory period is available under the NER for standard control services in the forthcoming period. The AER's preliminary position is based on the following considerations:

- Preliminary examination of the current control mechanism suggests that the current control mechanism satisfies the requirements of the NER.[138]
- To the extent that potential problems with incentives and risk associated with this form of control arise, they appear to be adequately addressed through adjustment mechanisms the same as, or similar to, those already in place.[139]

[138] NER cl. 6.5.2(c)(3)
[139] NER cl. 6.5.2(c)(5)

- It is unclear to the AER that any form of control imposed on ETSA Utilities is guaranteed to result in efficient tariff structures (under which prices reflect costs)[140], given the restriction on tariffs for small customers under clause 18.5(a) of the *National Electricity (South Australia) Act 1996,* and as prices charged to retailers would need to be passed on to the consumers in such a way that the relevant signals were not lost.
- Retention of the current form of control for all standard control services maintains consistency in regulation of those services within South Australia. The AER considers that consistency of regulatory approaches within jurisdictions is an important initial goal, while noting that achieving consistency across jurisdictions is a medium-to-longer-term objective.[141]
- Transition to a completely new form of control mechanism will not guarantee a reduction in administrative costs, and may itself create undesirable administrative costs.[142]

In preparing its final framework and approach paper from ETSA Utilities, the AER will consider whether a different form of control is more appropriate in light of submissions from ETSA Utilities and other interested parties.

3.6.2 Alternative control services

For the reasons set out in chapter 2, the AER's preliminary position is that none of the distribution services provided by ETSA Utilities will be classified as alternative control services in the forthcoming regulatory control period. The AER does not consider it necessary or appropriate to offer a preliminary position on what form of control may apply to such services in these circumstances.

[140] NER cl. 6.2.5(c)(1)
[141] NER cl. 6.5.2(c)(4)
[142] NER cl. 6.5.2(c)(2)

4 Application of 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 ETSA Utilities, and its reasons for that approach.

The objective of a STPIS is to provide incentives for DNSPs to maintain and improve service performance. Under an incentive regulation framework, DNSPs have an incentive to reduce costs. Cost reductions are beneficial to both the DNSP and its customers where service performance is maintained or improved. However, savings that result in lowered service levels provided to customers are not necessarily desirable. The STPIS serves to ensure that increased financial efficiency does not result in deterioration of service performance for customers.

The STPIS works as part of the building block determination. The STPIS provides a financial incentive (through its s-factor component) for DNSPs to maintain and improve performance by providing penalties or rewards to the DNSP for diminished or improved service compared to predetermined targets. A STPIS may also include a 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 National Electricity Rules

The AER's building block determination for ETSA Utilities for the next regulatory control period will specify how the STPIS is to be applied to ETSA Utilities in that period.[143] In its framework and approach paper for ETSA Utilities the AER must set out its likely approach, together with its reasons for the likely approach, to the application of a STPIS in that determination.[144]

4.2.1 AER's distribution STPIS

As part of the new framework for economic regulation of distribution services, the AER is required to develop and publish an incentive scheme, or schemes, to ensure that DNSPs maintain and, where efficient, improve upon, agreed levels of service. This scheme is the STPIS.[145]

On 1 April 2008, the AER released its proposed national STPIS to apply to DNSPs. The proposed scheme was then subject to a round of stakeholder consultation, during which ETSA Utilities made a submission. Issues raised in that submission have been taken into account in the final national STPIS and accompanying explanatory statement, released on 26 June 2008.

The following sections provide a brief outline of the AER's final national STPIS. The AER's final national STPIS is available on the AER's website, www.aer.gov.au.

[143] NER, cl. 6.3.2(a)(3)
[144] NER. cl. 6.8.1(b)(2)
[145] NER, cl. 6.6.2(a)

4.2.2 Structure of the STPIS

The STPIS has four components:

- reliability of supply
- quality of supply
- customer service
- guaranteed service levels (GSL).

4.2.2.1 S-factor

The first three components are collectively known as 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 the predetermined targets. The maximum revenue at risk under the s-factor is ± 3% of a DNSP's revenue for each year of the regulatory control period.[146]

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) and
- Momentary average interruption frequency index (MAIFI). [147]

Performance targets for these parameters are based on a DNSP's average historical performance over the last five years.[148] Targets for each parameter are set for segments of the distribution network identified, for example, by feeder type. This allows the STPIS to recognise variations in performance across the DNSP's network.

The incentive rates for this component, which determine the amount of any reward or penalty, are based on the value that customers place on reliability of supply.

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

[146] The AER retains discretion as part of its STPIS to alter this figure where doing so would achieve the objectives set out in cl. 6.6.2 of the NER.
[147] SAIFI refers to the sum of the duration of each sustained customer interruption (in minutes) divided by the total number of distribution customers. SAIDI 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.
[148] 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.

- streetlight repair
- new connections, and
- response to written enquiries

Of these, the STPIS assumes 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 is justified under the NER.

As with reliability of supply, customer service parameter performance targets are based on average performance over the previous five years. [149] Unlike targets for the reliability of supply component of the STPIS, targets for this component apply to the distribution network as a whole, and are not segmented.

Under the STPIS, the incentive rate for the telephone answering parameter is set at either minus 0.040 or a value determined from an applicable assessment of the value that customers attribute to the level of service proposed.

Reporting requirements

The STPIS requires the DNSP to annually report its performance against all applicable parameters.

4.2.2.2 Guaranteed service levels

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

4.2.3 Implementing the STPIS

The STPIS developed by the AER, and published on 26 June 2008, is designed to facilitate consistent application across the NEM, but can be implemented taking into account the circumstances of each DNSP.

In implementing the STPIS, the AER must take into account:[150]

- 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

[149] 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.
[150] NER, cl. 6.6.2(3)

- 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.

The AER must also:

- consult with the authorities responsible for the administration of relevant jurisdictional electricity legislation[151]
- ensure that service standards and service targets (including GSLs) set by the scheme do not put at risk the DNSP's ability to comply with relevant service standards and service targets (including guaranteed service levels) as specified in jurisdictional electricity legislation.[152]

4.3 Considerations in applying the STPIS to ETSA Utilities in the 2010-15 regulatory control period

Both the Essential Services Commission of South Australia (ESCOSA) and the South Australian Department of Transport, Energy and Infrastructure (DTEI) were given the opportunity to comment on the proposed STPIS. While submissions on the proposed scheme were not provided, the AER will take steps to ensure that ESCOSA and DTEI are consulted on the proposed application of the final STPIS to ETSA Utilities.

The AER has had regard to relevant service standards and targets, including GSLs specified in South Australian electricity legislation in reaching the preliminary positions set out in this chapter. As noted below, these standards and targets are currently under review. The AER will take the outcomes of this review into account to the extent that time constraints in the NER permit it to do so. The AER will work with ESCOSA with a view to better aligning any future review of jurisdictional service standards with the timelines for the framework and approach and distribution determination processes prescribed in the NER.

4.3.1 Current arrangements for ETSA Utilities

ETSA Utilities currently operates under a service standard framework implemented and administered by ESCOSA. The framework has three key components:

- Average service standards
- Service incentive scheme
- Guaranteed service levels (GSL)

[151] NER, cl. 6.6.2(b)(1)
[152] 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.

4.3.1.1 Average service standards

The average service standards for South Australia are contained in clause 1.2 of the Electricity Distribution Code (EDC). The average service standards are expressed in terms of the average performance delivered to customers in a given region of ETSA Utilities' network. There are three sub-elements of the average service standards to which ETSA Utilities must adhere:

Reliability

Reliability is measured by frequency and duration of supply interruptions. Supply interruptions can originate from problems at power stations, transmission lines (generally 275 kV and 132 kV), and the distribution network (generally 66 kV and less). The key parameters against which reliability is measured are SAIDI and SAIFI.

ETSA Utilities must use its 'best endeavours' to achieve the SAIDI and SAIFI targets specified in the 2005-2010 Electricity Distribution Price Determination (EDPD). [153] Such targets exclude upstream (generation of transmission related) interruptions.

Quality of supply

Quality of supply is measured by deviations of voltage from specific levels, and is a function of voltage occurring at a customer's supply address and at other points on the network. The distribution network must be designed, installed and operated in such a way that the voltage standards specified in the EDPD 2005-2010 can be met. Performance is assessed against the following measures:

- Voltage
- Voltage fluctuations
- Harmonic voltage distortions
- Voltage unbalance factor in 3 phase supplies, and
- Interference.

Customer service

The customer service component is measured by timeliness of responses to telephone and written enquiries, and timeliness in providing written explanations for interruption to supply (after customer requests). Again, ETSA Utilities must use its best endeavours to achieve customer service levels in each year.

4.3.1.2 Service incentive scheme

The service incentive scheme was developed in response to a survey undertaken by ESCOSA, which sought information on consumer preferences for improvements in services. This survey suggests that 85 per cent of customers were not willing to pay more for a higher level of service, and 15 per cent were willing to pay for a higher level of service. The service incentive scheme aims to improve service to this 15 per cent of 'worst served customers' by providing a financial incentive delivered through

[153] Best endeavours is defined in the EDC as 't*o act in good faith and use all reasonable efforts, skill and resources.'*

potential penalties and rewards in regulated revenues. If ETSA Utilities outperforms the standards, it is rewarded by being allowed to recover increased revenue from its customers. If it does not meet the standard, however, penalties apply in terms of permitted revenue recovery.

Schedule 2, Part A of the EDC specifies the manner in which ETSA Utilities will calculate its entitlement to incentive points under the service incentive scheme for each year. This calculation is then incorporated into the annual revenue adjustment for ETSA Utilities which occurs in accordance with the EDPD. The total financial incentive for the service incentive scheme has been limited to ±$37.5m over five years or $7.5m per annum, which represents approximately ±0.3% of ETSA Utilities' average annual prescribed revenue.[154]

4.3.1.3 GSL scheme

The GSL scheme was established within Part B of the EDC. ETSA Utilities is contractually bound to meet the relevant obligations relating to the GSL scheme for each customer within its distribution network.

The GSL scheme requires ETSA Utilities to make payments to customers whose received service is below set thresholds for timeliness of appointments, timeliness of connection, timeliness of repairing streetlights, and minimising the frequency and duration of supply interruptions.[155] This commitment is made by ETSA Utilities in its standard connection and supply contract, and takes the form of a contractual obligation.

4.3.1.4 ESCOSA review: South Australian jurisdictional service standards to apply to ETSA Utilities in the 2010-2015 regulatory period

In the forthcoming regulatory control period, the AER's STPIS will take the place of the existing service incentive scheme. While neither drives the other, the AER's STPIS will, as contemplated by the NER, operate concurrently with the average service standards and GSL scheme administered by ESCOSA in that period.[156] The average service standards and GSLs determined by ESCOSA are distinct from performance targets set by the AER in the STPIS, however, as noted above, the AER must ensure that its STPIS does not put ETSA Utilities' ability to comply with these requirements at risk.

ESCOSA is currently conducting a review of the South Australian jurisdictional service standards to apply to ETSA Utilities in the forthcoming regulatory control period. In its draft decision, released on 6 June 2008, ESCOSA has expressed a

[154] ESCOSA 2005-2010 Electricity Distribution Price Determination, Part A – Statement of Reasons, p. 48 http://www.escosa.sa.gov.au/webdata/resources/files/050405-EDPD_Part_A_StatementofReasons_Final.pdf
[155] *ETSA Utilities Service Standard Framework 2010-2015 Issues Paper, Chapter 2*, published by ESCOSA. http://www.escosa.sa.gov.au/webdata/resources/files/080208-ETSAUtilitiesSSF2010IssuesPaper.pdf
[156] Note to NER, cl. 6.6.2(b)(2)

commitment to work closely with the AER to ensure the integrity of this shared service standards framework for the 2010-15 regulatory control period.[157]

The timing of ESCOSA's draft decision means the AER has not been able to consider, in any detail, these conclusions in this preliminary position paper. ESCOSA's draft decision indicates, however, that in the forthcoming regulatory control period, "it will largely retain the existing set of average reliability and customer service standards, as well as the quality of supply standard and the GSL scheme".[158]

ESCOSA's final decision is expected in August 2008[159], which will allow the AER to take into account any change in position before the release of its framework and approach paper for ETSA Utilities in November 2008. However, while the draft decision indicates that the current targets for customer service standards will remain unchanged, the AER understands actual targets for reliability (SAIDI and SAIFI) will not be set until the second half of 2009.[160] This means that those targets will not be available at the time that ETSA Utilities must submit its regulatory proposal to the AER (31 May 2009). The AER expects to be in a position to consider ESCOSA's revised targets in its draft decision on the distribution determination, which is likely to be released in November 2009, and will aim to ensure that stakeholders have adequate opportunities to comment on the impact those targets may have on the implementation of the STPIS in its final decision.

4.4 Proposed application of the STPIS to ETSA Utilities

4.4.1 Consideration of NER criteria.

4.4.1.1 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

Incentive rates for reliability parameters under the s-factor scheme are set on the basis of the latest available economic study of Value of Customer Reliability (VCR), which estimates the value of service reliability as value per kilowatt hour of lost load for supply interruptions.[161] Weightings for each parameter are also based on the value that customers place on them. The incentive rate for the telephone answering parameter is based on the results of a customer willingness to pay survey undertaken in South Australia by KPMG and subsequent analysis by Essential Service

[157] ESCOSA, *Draft Decision: South Australian jurisdictional service standards to apply to ETSA Utilities in the 2010-15 regulatory control period*, 6 June 2008, p. 6 http://www.escosa.sa.gov.au/webdata/resources/files/080604-ServStds2010-2015_DraftDec.pdf

[158] ibid, p.8

[159] ibid, p.9

[160] ibid, p. 49. ESCOSA's decision to establish numerical values for SAIDI and SAIFI targets based on four years of data as at 30 June 2009 means that those values can not be calculated, and will not be known to ETSA Utilities or the AER, before that date.

[161] The scheme draws on the most recent study of VCR available (CRA, 2002, *Assessment of the Value of Customer Reliability* – report prepared for VENCorp, Melbourne), and its application in the ESCV's 2005-10 electricity distribution determination, 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. The STPIS permits DNSPs to propose different values where new analysis is available.

Commission Victoria. Therefore, the potential penalty or reward available to ETSA Utilities reflects the potential benefit to consumers, and how they value performance under the parameter in question.

4.4.1.2 Any current regulatory requirements to which the relevant DNSP is currently subject

The service standards framework that has, and will in part continue to apply to ETSA Utilities under the South Australian regulatory framework has been discussed above.

ETSA Utilities is currently subject to a GSL scheme administered by ESCOSA. To avoid undesirable duplication of regulatory obligations, the AER will not apply its own GSL scheme to the ETSA Utilities while the jurisdictional GSL scheme remains in place.

The AER's STPIS does not currently include a quality of supply component,[162] but for reliability of supply and customer service performance it will use parameters that also feature in the average service standards framework administered by ESCOSA. In setting targets for these parameters in the STPIS, the AER will have regard to any targets assigned to them in the form of average services standards by ESCOSA, but, subject to the requirement that the STPIS does not put at risk ETSA Utilities' ability to comply with ESCOSA's average service standards, is not bound to adopt them for the purpose of the scheme.[163]

4.4.1.3 The past performance of the distribution network

Targets for the reliability and customer service components of the s-factor will be based on the past performance of ETSA Utilities' network. The means that the AER will take the previous performance of ETSA Utilities' network, as reported to ESCOSA, into account when setting targets, so as not to set unduly high or low targets. In establishing these targets, expectations on the basis of past performance will be modified to take into account reliability improvements completed or planned, where these are included in ETSA Utilities' approved forecast capex for the 2010-15 regulatory control period, or were approved in the capex allowed under the 2005-10 EDPD, where these are expected to result in material improvements in supply. Targets may also be modified if other factors are identified that are expected to materially affect network reliability performance.

The AER is aware that, within the current regulatory control period, ETSA Utilities has introduced a new outage management system that has allowed it to record performance data with increased accuracy. Issues of data comparability for years before and after the introduction of the new system will be taken into account in the AER's consideration of the appropriate period of historical performance from which to determine performance targets for the forthcoming regulatory control period.

[162] In its draft decision, ESCOSA has indicated that they will require ETSA Utilities to continue to report on quality of supply parameters for the purposes of the average service standards in South Australia. See ESCOSA, *Draft Decision: South Australian jurisdictional service standards to apply to ETSA Utilities in the 2010-15 regulatory control period*, 6 June 2008, p. 25
[163] To the extent that these targets are available – see discussion in section 4.3.1.4 above.

4.4.1.4 Any other incentives available to the DNSP under the NER or the relevant distribution determination

Other incentive schemes applicable to ETSA Utilities 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 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 opex does not result in lower levels of service for customers.

The STPIS does not necessarily conflict with 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. The AER considers that if the effects of non-network alternatives on reliability (such as demand side response) were excluded under the STPIS, this would effectively pass on the risk of these mechanisms to reliability to customers rather than ETSA Utilities. This means the STPIS would not have a neutral impact on whether a demand side response should be used (see also section 4.4.1.7 below).

4.4.1.5 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 STPIS both penalises ETSA Utilities for deteriorating service levels, and rewards it for efficient improvements in service. These penalties and rewards take the form of negative and positive adjustments to annual revenue, so that the revenue earned by ETSA Utilities is tied to the level of service it actually provides. Any incentive to reduce costs at the expense of service levels is counterbalanced by the corresponding penalties under the STPIS.

4.4.1.6 The willingness of the customer or end user to pay for improved performance in the delivery of services

The willingness of ETSA Utilities' 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.

The AER notes the willingness to pay studies undertaken for ESCOSA in the current and previous regulatory control period, which have been interpreted to suggest that the majority of customers are satisfied with current electricity supply reliability given the price they pay[164], and that only a small percentage of customers were willing to pay for improved service.[165] 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

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[164] ESCOSA, *Draft Decision: South Australian jurisdictional service standards to apply to ETSA Utilities in the 2010-15 regulatory control period*, 6 June 2008, p. 38

[165] ibid., p. 40. The 2007 survey conducted by McGregor Tan showed that 9 per cent of business customers and 13 per cent of residential customers indicated a willingness to pay more for improved supply reliability.

reward or penalty available), in a way that reflects customers' priorities and their willingness to pay for improvements.

4.4.1.7 The possible effects of the scheme on incentives for the implementation of non-network incentives.

The incentive created by the DMIS is for ETSA Utilities to create and implement demand side management in response to network issues. The STPIS does not necessarily counter the incentives created by the DMIS.

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 in the absence of an adjustment to targets or an exclusion to recognise what is seen as a greater risk that targets will not be met. The AER considers, however, that the risk associated with non network alternatives is better placed with ETSA Utilities than its customers. The AER considers that where aspects of performance are within ETSA Utilities' control, the associated risk should also lie with ETSA Utilities.

4.5 GSL scheme

In its draft decision on the South Australian distribution service standards to apply to ETSA Utilities in the 2010-15 regulatory control periods, ESCOSA has indicated its intention to:

> …set guaranteed service levels to apply as a contractual term for contracts between ETSA Utilities and its distribution customers (other than where a negotiated connection and supply contract exists). The guaranteed service levels applicable under the Electricity Distribution Code will be carried forward for that purpose.[166]

The AER will not apply the GSL component of its STPIS to ETSA Utilities whilst ESCOSA continues to administer the current GSL scheme.

The AER notes that ESCOSA has not, in its draft decision, included a risk mitigation mechanism to account for GSL payments potentially arising from extraordinary events, but has invited further submissions on this matter.[167] The AER will consider the impact of such a mechanism, and the extent to, and manner in which it makes provision for the payment of GSLs in its distribution determination for ETSA Utilities, at the time it makes that determination.

4.6 S-factor

4.6.1 Timing

Clause 2.3 of the AER's current STPIS provides that where a DNSP's regulatory control period commences on 1 January or 1 July, annual performance must be measured from 1 July until 30 June inclusive. The regulatory control period for ETSA

[166] ESCOSA, *Draft Decision: South Australian jurisdictional service standards to apply to ETSA Utilities in the 2010-15 regulatory control period*, 6 June 2008, p. 62
[167] ibid.

Utilities begins on 1 July 2010, so that ETSA Utilities will be required to measure performance under the STPIS from that date.

4.6.2 Revenue at risk

The AER's national STPIS sets a maximum ±3 per cent of revenue at risk. That is, the maximum amount that a DNSP can be penalised or rewarded under the s-factor component of the STPIS is 3 per cent of its total allowed revenue for any year of the regulatory control period. This amount is distributed across all parameters (and in the case of reliability of supply parameters, all segments of the network), with the weighting assigned to each reflecting the value of that measure to customers.

The AER will generally set revenue at risk under the s-factor at 3 per cent for all DNSPs. Exceptions to this may be considered and implemented in the distribution determination, where an alternative proposal which satisfies the objectives of cl. 1.4 of the STPIS, and the objectives contained in 6.6.2 (b)(3) of the NER, is submitted by a DNSP.

The AER's preliminary position is to place ±3 per cent of ETSA Utilities' revenue at risk under the STPIS. The distribution of the revenue at risk across performance parameters (and where applicable network segments), and the targets and incentive rates applied under the STPIS will ensure that the amount of any reward or penalty paid under the STPIS will be proportionate to the value customers place on the associated change in performance levels.

4.6.3 STPIS applied within a control mechanism

The AER's STPIS explanatory statement states that:

> How the S-factor will be incorporated into the form of control will be outlined for each business during consultation on its framework and approach for a distribution determination.[168]

The AER's preliminary position is that the s-factor will be incorporated into the revenue equation as specified in chapter three of this paper.

4.6.4 Reliability of supply component

4.6.4.1 Parameters

The STPIS allows for the potential inclusion of three parameters for reliability of supply: SAIDI, SAIFI and MAIFI.

In its draft report, ESCOSA has indicated that average service standards will be applied to both SAIDI and SAIFI in the forthcoming regulatory control period.[169] The AER's preliminary position is that these parameters will also apply under the STPIS.

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[168] AER, *Explanatory statement and Discussion paper-Proposed Electricity DNSPs - STPIS* April 2008, p. 10.

[169] ESCOSA, *Draft Decision: South Australian jurisdictional service standards to apply to ETSA Utilities in the 2010-15 regulatory control period*, 6 June 2008, p. 35 http://www.escosa.sa.gov.au/webdata/resources/files/080604-ServStds2010-2015_DraftDec.pdf

While no target has been attached to it in ESCOSA's average service standards, in the current regulatory control period ETSA Utilities has also reported on MAIFI. For these purposes, the data is provided using a sampling technique that, while perhaps sufficient to indicate trends in MAIFI over time, is not suited to an incentive mechanism such as the STPIS, which attaches financial rewards and penalties to performance. At this time, the AER does not intend to include MAIFI targets in the application of the STPIS to ETSA Utilities in the forthcoming regulatory control period.

The STPIS provides that the DNSP's network must be segmented to measure reliability performance. The STPIS contemplates the use of the familiar, and commonly used SCONRRR feeder categories for this purpose, but allows network areas to be segmented by a method other than feeder type where the alternative better meets the objectives of the scheme set out in clause 1.4 of the STPIS.

In the current regulatory control period, ETSA Utilities' network has been divided into seven geographic regions selected by ESCOSA for the purpose of measuring service performance, each representing a differing degree of network volatility:

- Adelaide business area
- Barossa/Mid north and Yorke Peninsula/Riverland/Murrayland
- Eastern Hills/Fleurieu Peninsula
- Major metropolitan areas
- South East
- Upper North and Eyre Peninsula and
- Kangaroo Island.

Since 2002/03, ETSA Utilities has also reported annually on its performance against both SAIDI and SAIFI for the SCONRRR feeder categories on which the default segmentation in the AER's STPIS is based, as part of its national comparative performance data reporting.[170] ESCOSA has noted that "the Adelaide Business Area and Major Metropolitan Areas generally capture feeders which would otherwise be within the CBD and Urban SCONRRR categories".[171] The AER understands the remaining regions to include a mix of short and long and rural feeders.

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[170] Reports against a core set of nationally consistent performance monitoring requirements for the electricity industry; details of which are published at titled "National Regulatory Reporting for Electricity Distribution and Retail Businesses, Utility Regulators Forum discussion paper", March 2002, refer: http://www.accc.gov.au/content/index.phtml/itemId/332190/fromItemId/3894 National Regulatory Reporting for Electricity Distribution and Retail Businesses, Utility Regulators Forum discussion paper, March 2002, sets out the reporting requirements that ESTA Utilities must adhere to http://www.accc.gov.au/content/index.phtml/itemId/332190/fromItemId/3894

[171] South Australian Jurisdictional Service Standards to apply to ETSA Utilities in the 2010-2015 regulatory period draft decision, p. 45 http://www.escosa.sa.gov.au/webdata/resources/files/080604-ServStds2010-2015_DraftDec.pdf

In response to the current consultation on the service standards framework administered by ESCOSA, ETSA Utilities has submitted that the current geographic segmentation of the network should not be continued, and the SCONRRR feeder classifications be adopted in their place.[172]

> ETSA Utilities has found that geographic regions are highly influenced by localised weather and show significant variability in performance from year to year as a result. This makes it very difficult to meaningfully analyse performance trends over time.

ETSA Utilities goes on to recommend that in the interests of national consistency, the reliability standards for the 2010 to 2015 period should be based on the SCONRRR feeder classification regime and not regions[173], and that:

> …reliability targets based on the SCONRRR feeder categories reflect the design of ETSA Utilities' network with the:
>
> - CBD (ie Adelaide Business Area) being designed to achieve very good reliability performance, by incorporating multiple redundancies (ie more than one or two electricity supply sources);
> - Urban (nearly identical to Major Metropolitan) where in general supply can be restored to the majority of customers without repairing the fault; and
> - Rural (Short and Long) where the network is radial and some customers can be restored up to the fault location, but customers beyond the fault cannot be restored until the fault has been repaired. Rural long feeders are longer (i.e. greater than 200kms) and take longer to locate and to repair the fault than Short Rural feeders.[174]

In contrast, other submissions supported a greater degree of regional separation, citing distortions in data arising from averaging performance within the existing regions.[175]

In its draft decision, ESCOSA accepts the importance of being able to benchmark ETSA Utilities' reliability performance with performance in other jurisdictions, and proposes to continue to require ETSA Utilities to report its performance against the SCONRRR feeder classifications for that purpose.[176] However, ESCOSA has indicated its intention to retain the current regional separation for the purposes of setting reliability standards for the 2010-15 regulatory control period, noting that:

> …the move to 7 regions has, to date, provided valuable insights into variations in reliability performance across the State. [177]

ESCOSA has indicated that, given the potential volatility of reported reliability performance when measured across a greater number of regions, it does not support proposals for further separation.[178]

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[172] ESCOSA, *Draft Decision: South Australian jurisdictional service standards to apply to ETSA Utilities in the 2010-15 regulatory control period*, 6 June 2008, p. 3 http://www.escosa.sa.gov.au/webdata/resources/files/080604-ServStds2010-2015_DraftDec.pdf
[173] ibid., p. 9
[174] ibid.
[175] ibid., p. 42
[176] Ibid., p. 45
[177] ibid., p. 45-46
[178] ibid., p.44, 45

While recognising their potential value in providing more transparency in reliability of performance across regions, and their suitability on that basis for setting average performance standards of the nature administered by ESCOSA, the AER's preliminary position is that the difficulties in identifying trends in performance over time limits the usefulness of the current regional separation in the context of the STPIS. For the purposes of developing targets under the STPIS, to which financial rewards and penalties are attached, segmentation in accordance with the SCONRRR feeder types is considered more appropriate. Consistency with segmentation of networks in other jurisdictions to which the STPIS applies will also allow the AER to monitor consistency in the incentives created by its STPIS over time.

The relatively close correlation, however, between the SCONRRR feeder types and the ESCOSA regions is such that the AER does not consider that different approaches to segmentation of the network in the STPIS and average service standards frameworks will put ETSA Utilities' ability to comply with the latter at risk. Nonetheless, the AER will have regard to the outcomes of ESCOSA's ongoing consultation on this issue in making its final decision.

4.6.4.2 Performance targets

Performance targets under the STPIS are to be based to the extent possible on average performance over the past five years. This data can be modified[179] to reflect reliability improvements that have affected service reliability or other factors that materially affect network reliability performance. Any modifications to performance data must be accompanied by appropriate justification when submitted by a DNSP. Targets for each applicable parameter, and each segment to which the parameter applied, will be set on this basis at the time of the distribution determination.

In July 2005, ETSA Utilities implemented an Outage Management System (OMS), to enable accurate reporting of high and low voltage interruptions.[180] In submissions to the AER and to ESCOSA, ETSA Utilities has noted that OMS data is only available from 1 July 2005, and that an accurate translation from the manually reported reliability data available prior to that date to the more accurate OMS data (which it submits has an error margin of less five than per cent) is not possible.[181] On this basis it has expressed concern that five years of continuous, comparable data will not be available at the time that the AER's distribution determination is made (and targets for the STPIS are set).

The AER does not consider this to be an obstacle to the application of the STPIS and the development of appropriate targets for the forthcoming regulatory control period. The absence of five years of data does not automatically exclude the application of a parameter under the STPIS, where appropriate alternative benchmarks or methodologies are available. In this respect the AER notes ESCOSA's intention to set reliability targets on the basis of performance in the four years to 30 June 2009, and considers that a similar approach could be taken to setting targets for the STPIS. The implications of this approach for the availability of data at the time that ETSA Utilities must submit its regulatory proposal to the AER (one month before the period of measurement ends) have been noted above. The AER will work with ESCOSA and

[179] In accordance with cl. 3.2.1 (a) (1) or (2) of the AER's STPIS
[180] *ETSA Utilities submission to ESCOSA Issues paper*, p. 9
[181] ibid., p. 9

ETSA Utilities to identify a workable approach to this in the distribution determination process.

4.6.4.3 Incentive rates

Incentive rates under the AER's STPIS are based on the value that customers place on supply reliability (VCR).

ETSA Utilities, in its regulatory proposal, will be required to propose incentive rates in accordance with the methodology set out in the STPIS, but may elect to propose an alternative VCR. Should ETSA Utilities elect to do this, it must provide the AER with the methodology used to calculate the value and research supporting its calculation.

Incentive rates will be calculated at the commencement of the regulatory control period (in the distribution determination) and will apply for the duration of the regulatory control period.

4.6.4.4 Exclusions

The AER notes that for SAIFI and SAIDI, sustained interruptions caused by transmission or generation failures are excluded from the scheme. The following exclusions, contained in cl.3.3 of the STPIS, will apply to ETSA Utilities:

- any day (midnight to midnight) where daily unplanned SAIDI for the electricity distribution network exceeds the major event delay threshold as set out in appendix D of the STPIS
- load shedding due to generation shortfall
- automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition
- load shedding at the direction of NEMMCO or a system operator
- load interruptions caused by failure of the shared transmission network and
- 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
- load interruptions caused by the exercise of any obligation, right or discretion imposed up on or provided for under jurisdictional electricity legislation applying to a DNSP.

4.6.5 Quality of supply component

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

The AER understands that ESCOSA will continue to require ETSA Utilities to report performance against quality of supply measures in the forthcoming regulatory control period. While this reporting requirement continues, the AER will not require ETSA Utilities to report separately on these measures, but will observe the reported results in each year. This will allow the AER to collect and publish valuable data that will inform the development of quality of supply parameters for the STPIS in future regulatory control periods. The AER will work with ETSA Utilities and ESCOSA to ensure that it is able to access this data.

4.6.6 Customer service component

4.6.6.1 Parameters

The AER's preliminary position is that the telephone answering parameter in the customer service component of its STPIS should be applied to ETSA Utilities in the forthcoming regulatory control period. ESCOSA has indicated that this measure will also be retained in the average service standards framework that it will administer.[182] The definition of the telephone answering parameter adopted in the STPIS is the same as that currently used by ESCOSA.

ETSA Utilities may, in its regulatory proposal, proposed that application of other customer service parameters under the STPIS. The AER notes in this respect that the average service standards administered by ESCOSA are expected to include a target for time to respond to written enquiries.[183] The AER will only require ETSA Utilities to include additional customer service parameters where it considers that the service being measured by the parameter is not subject to effective competition.

4.6.6.2 Revenue at risk

The revenue at risk for all customer service parameters will be no more than 1% of total revenue for each year of the regulatory control period. The maximum revenue at risk for any individual parameter is 0.5% of revenue for each year of the regulatory control period. The AER's preliminary position is that a maximum value of 0.5% will be attached to the telephone answering parameter in the forthcoming regulatory period.

4.6.6.3 Performance targets

Clause 5.3.1(a) of the AER's STPIS provides that performance targets for each customer service performance parameter are to be based on average performance over the past five years. As noted above, these targets apply to the network as a whole rather than to network segments. Any modifications to performance data proposed for the purposes of setting targets must be accompanied by appropriate justification in ETSA Utilities' regulatory proposal.

ETSA Utilities has been monitoring and reporting on the telephone answering component under its current service standards framework administered by ESCOSA since 1999. Therefore ETSA Utilities is expected to have the relevant historical data required to set targets for the forthcoming regulatory control period.

In setting targets, and in determining the appropriate amount of revenue that will be at risk under this component of the STPIS, the AER will have regard to ETSA Utilities' performance in the current regulatory control period and to the corresponding target set by ESCOSA. In its draft decision on service standards to apply to ETSA Utilities in the 2010-15 regulatory control period, ESCOSA has indicated its intention to

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[182] ESCOSA, *Draft Decision: South Australian jurisdictional service standards to apply to ETSA Utilities in the 2010-15 regulatory control period*, 6 June 2008, p. 27 http://www.escosa.sa.gov.au/webdata/resources/files/080604-ServStds2010-2015_DraftDec.pdf

[183] ibid

maintain the current target of 85% of calls answered within 30 seconds, including calls after a major outage event.[184] ETSA Utilities has exceeded this target in both 2005/06 and 2006/07, reporting performance of 85.2% and 89.3% respectively[185].

Any other parameters proposed by ETSA Utilities should be accompanied by proposed targets developed on a comparable basis.

4.6.6.4 Incentive rate

The incentive rate for the telephone answering parameter is set by the STPIS at -0.040. For other parameters proposed by ETSA Utilities the appropriate incentive rates should be based on the value that customers attribute to the level of service proposed.

Incentive rates will be calculated at the commencement of the regulatory control period (in the distribution determination) and will apply for the duration of the regulatory control period.

4.6.6.5 Exclusions

Clause 5.4 (a) provides that:

> Where the impact of an event is allowed to be excluded from the calculation of a revenue increment or decrement under the reliability of supply component of this scheme (under 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*.

Where ETSA Utilities proposes other customer service parameters in its regulatory proposal, it may also propose appropriate exclusions for these parameters.

4.7 AER's preliminary positions on the application of a STPIS to ETSA Utilities

The AER's preliminary position is that it is likely to apply the reliability of supply and customer service components of the STPIS to ETSA Utilities in the forthcoming regulatory control period.

Targets for the reliability of supply component will be attached to SAIDI and SAIFI, with separate targets for each segment of the network, in accordance with the SCONRRR feeder categories identified in the STPIS. Targets will reflect available data on historical performance, with adjustments as necessary under the STPIS. The AER does not consider the sampling method currently utilised in ETSA Utilities' reporting of MAIFI is a suitable basis of performance measurement for a financial incentive such as the STPIS, and will not include MAIFI as a parameter for ETSA Utilities at this time.

There will be no quality of supply component for the forthcoming regulatory control period. However, the AER will monitor ETSA Utilities' quality of supply

[184] ESCOSA, *Draft Decision: South Australian jurisdictional service standards to apply to ETSA Utilities in the 2010-15 regulatory control period*, 6 June 2008, p. 58 http://www.escosa.sa.gov.au/webdata/resources/files/080604-ServStds2010-2015_DraftDec.pdf

[185] ibid., p. 25

performance as reported to ESCOSA, and will explore the desirability of including quality of supply parameters in its STPIS in future regulatory control periods.

For the customer service component, the AER proposes that the telephone answering parameter (as defined in appendix A of the AER STPIS) will apply to ETSA Utilities for the forthcoming regulatory control period. Other parameters under this component may be proposed by ETSA Utilities in its regulatory proposal.

The AER will not apply the GSL component of the STPIS to ETSA Utilities in the forthcoming regulatory control period.

In forming this position, the AER has had regard to the matters identified 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 South Australian customers to pay for improved performance in the delivery of services by ETSA Utilities.[186] The use of VCR in setting incentive rates and weightings also means that any rewards or penalties under the STPIS also means that any potential benefits to consumers under the STPIS are sufficient to warrant any reward or penalty under the scheme for ETSA Utilities.[187]

- The AER's STPIS will necessarily operate concurrently with ESCOSA's average service standards. Whilst the s-factor component of the AER's STPIS creates financial incentives for ETSA Utilities, the average service standards have no financial incentive, and therefore there is no risk of double penalty to ETSA Utilities. As stated above, no AER administered GSL component will apply to ETSA Utilities whilst ESCOSA continues to implement a GSL scheme.[188]

- ETSA Utilities, whilst being penalised for diminished performance, has the opportunity to gain financially for performance that exceeds targets. Any incentive to reduce costs at the expense of service levels is counterbalanced by the corresponding penalties under the STPIS.[189]

- The AER's STPIS considers the past performance of the distribution network by setting s-factor targets based on average historical performance of ETSA Utilities. This ensures that targets are not set excessively high or low.[190]

- The AER's STPIS is designed to operate in conjunction with both the DMIS and EBSS. The STPIS balances the potential for the EBSS to incentivise inefficient reductions in opex at the risk of service levels. By facilitating development and implementation of viable non-network solutions and demand management strategies, the DMIS operates to reduce the perceived performance risk of implementing non-network alternatives to augmentation.

[186] NER, cl. 6.6.2(3)(vi)
[187] NER, cl. 6.6.2(3)(i)
[188] NER, cl. 6.6.2(3)(ii)
[189] NER, cl. 6.6.2(v)
[190] NER, cl. 6.6.2(3)(iii)

5 Application of efficiency benefit sharing scheme

5.1 Introduction

The AER's building block determination for ETSA Utilities for the forthcoming regulatory control period must specify how any applicable efficiency benefit sharing scheme (EBSS) will apply to ETSA Utilities.[191]

This chapter sets out the AER's likely approach to the application of an EBSS to ETSA Utilities in the forthcoming regulatory control period, and its reasons for that approach. Chapter 7 covers certain transitional issues associated with the operation of the existing efficiency carryover mechanism that currently applies to ETSA Utilities under the 2005-10 Electricity Distribution Price Determination (EDPD), and how the outcomes of that scheme will impact in the forthcoming regulatory control period.

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 the DNSP's operating expenditure (opex) for a regulatory period.

In the absence of an EBSS, the natural incentive for DNSPs is to realise efficiency gains early in the regulatory control period, as they can only retain the benefit from these for the remainder of the regulatory control period. Firms may also have a natural incentive to increase their actual opex 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 opex forecasts for the forthcoming regulatory period. The combined effect of these incentives is that the incentive for DNSPs to improve the efficiency of their opex declines throughout the regulatory control period, and consequently the incentive for DNSPs to improve the efficiency of their opex declines as well. One of the objectives of the EBSS is to create a continuous incentive for DNSPs to find economically efficient ways to reduce their opex in each year of the regulatory control period.

5.2 Requirements of the National Electricity Rules

The AER's distribution determination for ETSA Utilities for the forthcoming regulatory control period will specify how the EBSS is to be applied to ETSA Utilities in that period.[192] In its framework and approach paper, the AER must set out its likely approach, and its reasons for that approach, to the application of the EBSS in that determination.[193]

5.2.1 AER's distribution EBSS

As part of the new framework for economic regulation of distribution services, the AER is required to develop and publish a scheme or schemes that provide for a fair sharing between DNSPs and users of:

[191] NER, cl. 6.3.2(a)(3)
[192] NER, cl. 6.3.2(a)(3)
[193] NER, cl. 6.8.1(b)(3)

- the efficiency gains derived from the opex of DNSPs for a regulatory control period being less than; and
- the efficiency losses derived from the opex of DNSPs for a regulatory control period being more than,

the forecast opex approved or substituted by the AER for that regulatory control period.[194]

The AER's EBSS was published on 26 June 2008, and is available on the AER's website at www.aer.gov.au.

The scheme calculates revenue increments or decrements derived from the difference between a DNSP's actual opex and the forecast opex 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 the 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 DNSPs and their customers.[195] This means that the DNSP will retain 30% of the benefits of efficiency gains, and customers 70%.

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.

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 opex
- the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses
- any incentives the DNSP may have to capitalise expenditure
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.[196]

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194 NER, cl. 6.5.8(a)

195 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.

196 NER, cl. 6.5.8(c)

The AER's distribution EBSS was developed with regard to these same considerations.

The AER's preliminary position on the application of the EBSS in ETSA Utilities' distribution determination for the 2010-15 regulatory control period is set out in the sections below.

5.3 Application of EBSS to ETSA Utilities

The AER has developed an EBSS in accordance with the requirements of the NER, which it intends to apply to ETSA Utilities in the forthcoming regulatory control period. The EBSS was developed with regard to the criteria contained in cl. 6.5.8(c). The AER must also have regard to these criteria in applying the EBSS to ETSA Utilities. In this way, the design of the EBSS will itself ensure that its application to ETSA Utilities (and other DNSPs) is consistent with the criteria established in the NER.

5.3.1 Background and operating environment

ETSA Utilities actual annual opex compared to its allowable annual opex in the 2000-05 regulatory control period is set out below.

Table 5.1: ETSA Utilities – actual opex compared to allowable opex for the 2000-2005 regulatory control period ($m, nominal)

Opex	2000/01	2001/02	2002/03	2003/04	2004/05
ESCOSA benchmarks (CPI adjusted)	100.65	88.86	89.12	89.39	90.42
Actual opex	77.01	81.40	86.60	96.81	97.04

Source: ESCOSA's 2005 -2010 Electricity Distribution Price Determination, Part A: Statement of Reasons, p.73

In the first three years of the 2000-2005 regulatory control period ETSA Utilities' actual opex was below the annual amount approved by ESCOSA in its 2000-2005 EDPD. In 2003/04, and 2004/05 ETSA Utilities overspent on its allowed opex by approximately $7.42m and $6.62m respectively.

For the current regulatory control period, ESCOSA approved an opex allowance of $649 million in opex for ETSA Utilities (24 per cent more than the previous regulatory control period). This allowance was based on forecast annual growth of 3 per cent in peak demand and an average annual 1.4 per cent growth in energy sales over the regulatory period.

The $649 million allowance for 2005-10 was allocated annually as follows:

Table 5.2 : ETSA Utilities – allowances for current regulatory period (2004 $m)

Opex	2005/06	2006/07	2007/08	2008/09	2009/10	Total
ESCOSA benchmarks	124	130	131	132	132	649

Source: ESCOSA's 2005 -2010 Electricity Distribution Price Determination, Part A: Statement of Reasons, p.100.

ETSA Utilities is currently subject to an efficiency carryover mechanism, which has been administered by ESCOSA in the current regulatory control period in accordance with the 2005-10 EDPD. This mechanism works in conjunction with the incentive contained within the CPI-X control mechanism to improve efficiency in expenditure during the regulatory control period.

The efficiency carryover scheme was premised on allowing ETSA Utilities to retain annual efficiency gains for a set carryover period of five years. The mechanism offers rewards to ETSA Utilities for efficiency gains to both capex and opex.[197] The current mechanism is also symmetrical, in that it treats positive and negative carryovers equally. This is the first regulatory control period in which ETSA Utilities is subject to negative carryovers.

5.3.2 Consideration of the NER criteria

As noted above, the AER must have regard to a number of factors in implementing the EBSS. These are discussed in turn below. Recognition of these factors in the development of the EBSS itself is discussed in more detail in the final decision on the electricity distribution network providers EBSS and accompanying explanatory statement, which is available on the AER's website (www.aer.gov.au).

5.3.2.1 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 ETSA Utilities

In developing the scheme, the AER selected a 5 year carryover period (the length of a standard regulatory control period). This results in a sharing ratio between customers and ETSA Utilities of 70:30. That is, where an efficiency is realised and a subsequent opex underspend occurs, the EBSS passes back 70% of this amount to ETSA Utilities' consumers in the form of price reductions. This occurs over a five year period from the year the efficiency was made, which 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% sharing ratio allocation where a loss is made. Therefore whilst ETSA Utilities must share the benefits of any gains, the costs of any losses are also borne by consumers in the form of increased prices. The risk that customers incur higher prices due to efficiency losses is mitigated by the continuous incentive for ETSA Utilities to strive for efficiency gains created by the EBSS.

[197] Asset utilisation and transmission services were not treated separately from opex and capex efficiency gains.

The EBSS provides greater certainty to ETSA Utilities on how actual opex will be used to set forecasts in future periods. Without an EBSS, the incentive to improve efficiency decreases as the period progresses and there can be uncertainty as to how opex 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 ETSA Utilities to reveal its efficient opex. Consequently, the AER will be better placed to determine efficient forecasts going forward, and in time, these benefits will be passed back to consumers.

5.3.2.2 The need to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure and, if the scheme extends to capital expenditure, capital expenditure

The EBSS is designed to ensure that a DNSP facing a potential efficiency gain does not perceive a material advantage in either deferring or advancing an efficiency gain or loss, but rather that it faces an essentially constant benefit or cost from implementing a gain or loss as it arises. The measurement of gains and losses should not be artificially affected by, for example, shifting costs between years. Rather, it should represent genuine business outcomes that have arisen in the ordinary course of conducting the business in a prudent and diligent manner.

Under an incentive regulation framework such as that in the NER, 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 ETSA Utilities to realise opex efficiencies early in the regulatory control period, so that the benefit of that efficiency can be retained for a longer period of time. By allowing ETSA Utilities to retain the benefit of an efficiency gain for the length of the carryover period (5 years) regardless of the regulatory year in which it is achieved, the EBSS reduces this incentive.

There is also a perceived incentive for ETSA Utilities to increase opex 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 opex requirements for the following regulatory control period.

This incentive to increase opex for the regulatory period in year four is at least partly counteracted by the symmetrical nature of the scheme. DNSPs may be inclined to strategically defer opex until the base year, to increase opex forecasts for following regulatory 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 the DNSP from increasing opex in the base year will have to be weighed up against the penalties that will be incurred for 5 years after the overspend.

The AER's EBSS thus provides ETSA Utilities 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 opex. This decision is explained in the AER's Electricity distribution network service providers' efficiency benefit sharing scheme final decision (accompanying the EBSS), which is available on the AER's website at www.aer.gov.au.

5.3.2.3 The desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses

In developing the 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 opex 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.

Any negative or positive carryover amount will be included as a building block element in the calculation of ETSA Utilities' allowed revenue for the following 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 opex efficiencies only during the early years of the regulatory control period.

5.3.2.4 Any incentives that DNSPs may have to capitalise expenditure

An important outcome of the EBSS is that it provides a constant incentive to ETSA Utilities to improve efficiency of opex throughout the regulatory period. Because the AER's EBSS only applies to opex and not capex, ETSA Utilities may have an incentive to reallocate opex to capex, thereby creating an artificial opex efficiency. This incentive is mitigated by the AER's requirement that ETSA Utilities 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 opex. To negate any incentive to capitalise opex where it is not efficient to do so, the AER will adjust the forecast and actual opex 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 opex, rather than capex. Because the EBSS is not applied to capex, the incentive later on in the regulatory control period to reduce capex is less than the incentive to reduce opex. Therefore, where expenditure for non-network alternatives is operational, ETSA Utilities 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 removes the potential impact of the EBSS on such decisions, which may otherwise discourage ETSA Utilities from considering demand side management.

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

The AER's preliminary position is that the EBSS will be applied to ETSA Utilities in the forthcoming regulatory control period. In forming this position, the AER has had regard to the matters identified in clause 6.5.8(c) of the NER, and considers that:

- the benefits to South Australian consumers derived from the EBSS are sufficient to warrant any financial reward or penalty that ETSA Utilities may incur, because South Australian distribution customers receive 70% of the efficiency gains realised by ETSA Utilities under the EBSS.[198] Because the EBSS is symmetrical, any efficiency losses are also shared between the customer and ETSA Utilities, so that the potential for financial penalty is balanced.[199] The symmetry of the scheme also provides balance so that incentives are not skewed in favour of realising opex efficiencies only during the first years of the regulatory control period. This also removes the perceived tendency towards strategic deferral of opex to the final years of the regulatory control period in order to create an artificially high base year for future forecasts.

- the EBSS will provide a continuous incentive for ETSA Utilities to achieve opex 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 was realised.[200]
- the EBSS will counter any artificial incentive to capitalise expenditure, by requiring ETSA Utilities to report on any changes on its capitalisation policy to the AER and adjusting the forecast and outturn opex figures used to determine the carryover amounts to account for any changes in capitalisation policy.[201]
- the exclusion of costs associated with demand side management from consideration under the EBSS removes any deterrents to the use of non network alternatives that might otherwise arise under the EBSS.[202]

The EBSS requires ETSA Utilities to propose any categories of uncontrollable opex that will be excluded from the operation of the EBSS as part of its regulatory proposals. The EBSS also invites ETSA Utilities to include, as part of its regulatory proposal, any proposals on the relevant growth adjustments methods to be applied to factor growth into its opex forecast. These issues will be decided in the distribution determination process, and will not be addressed in the framework and approach paper.

[198] NER, cl. 6.5.8(c)(1)
[199] NER, cl. 6.5.8(c)(3)
[200] NER, cl. 6.5.8(c)(2)
[201] NER, cl. 6.5.8(c)(4)
[202] NER, cl. 6.5.8(c)(5)

6 Application of demand management incentive scheme

6.1 Introduction

This chapter sets out the AER's likely approach to the application of a demand management incentive scheme (DMIS) to ETSA Utilities, 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.[203] The DMIS operates in conjunction with existing incentives in the regulatory framework to pursue these objectives.

Demand management refers to the implementation of any strategy to address growth in demand or peak demand. Network owners can seek to undertake demand management through a variety of mechanisms, such as incentives for customers to change their demand patterns, operational efficiency programs, or load control technologies. Demand management can provide efficient alternatives to network investments, by deferring the need for augmentations to relieve network constraints. This can have positive impacts by reducing inefficient peaks and encouraging more efficient use of existing network assets, resulting in lower prices for network users.

6.2 Requirements of the National Electricity Rules

The AER's distribution determination for ETSA Utilities for the 2010-15 regulatory control period will specify how a DMIS will be applied to ETSA Utilities in that period.[204] In its framework and approach paper for ETSA Utilities, the AER must set out its likely approach, together with the reasons for that approach, to the application of a DMIS in that determination.[205]

6.2.1 DMIS applicable to ETSA Utilities

As part of the new framework for economic regulation of distribution services the NER allow the AER to develop and publish an incentive scheme or schemes (DMIS) 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.[206] Unlike the service target performance incentive scheme (STPIS) and the efficiency benefit sharing scheme (EBSS), the AER is not required to develop a DMIS. However, where it does elect to do so, it must follow the distribution consultation procedures set out in the NER.[207]

Consultation on a DMIS suitable for consistent application across the NEM has not yet commenced. A national DMIS will not be sufficiently developed in time for the AER to prepare and consult on a likely approach to its application to ETSA Utilities

[203] NER, cl 6.63(a)
[204] NER, cl. 6.3.2(a)(3)
[205] NER, cl. 6.8.1(b)(4)
[206] NER, cl. 6.6.3(a)
[207] NER, r. 6.16

before it must publish its framework and approach paper on 30 November 2008. For that reason, the AER has consulted separately on the development of a DMIS that can be applied to ETSA Utilities, and to Energex and Ergon Energy, whose framework and approach papers are to be completed on the same day (SA-Qld DMIS). A proposed SA-Qld DMIS was published on 30 June 2008.

This paper sets out the AER's preliminary position on the application of the proposed SA-Qld DMIS to ETSA Utilities. In its final framework and approach paper, the AER will take into account submissions on both this paper and the proposed SA-Qld DMIS in setting out its likely approach to the application of the final SA-Qld DMIS to ETSA Utilities.[208]

6.2.2 Structure of the DMIS

The AER's proposed DMIS, released on 30 June 2008, is in the form of a demand management innovation allowance.

The demand management innovation allowance aims to encourage DNSPs to undertake efficient innovative or broad-based demand management which may assist in providing long-term benefits to consumers and ETSA Utilities via lower overall demand on the network, and lower prices.

The demand management innovation allowance will take the form of an annual ex ante allowance provided as a fixed amount of additional revenue at the commencement of each regulatory year. The total amount recoverable under the allowance within a regulatory control period will be capped at an amount that is broadly proportionate to the size of the DNSP's annual revenue requirement in the previous regulatory period, and distributed evenly across each year of the regulatory control period. This approach is consistent with that taken in the development of the innovation allowance for DNSPs in NSW and the ACT determinations, in that the allowance for ETSA Utilities will be proportionate to that given to DNSPs of comparable size in other jurisdictions.

Expenditure under the allowance will be assessed annually on an ex post basis, against criteria established in the scheme. While the allowance will be made available on an ex ante basis, only approved expenditure will be deemed recoverable. The amount of any expenditure that is not approved will be deducted from the allowed revenue in the subsequent regulatory control period. Any underspend accumulated at the end of the relevant regulatory period will not be retained in the next regulatory period, and will also be deducted from revenue in the subsequent regulatory period. This adjustment will also adjust for the time value of money, to render the scheme insensitive to expenditure profiles over the regulatory control period.

The AER will require that the application for cost recovery is made public as part of a report on demand management programs carried out by DNSPs. In addition, at the completion of the DNSPs' annual service standards reviews, the AER will publish the

[208] Should consultation on the development of a national DMIS be sufficiently advanced at the time ETSA Utilities submits its regulatory proposal to the AER on 31 May 2009, it will be open to ETSA Utilities to propose application of the national scheme in its distribution determination for the 2010-15 regulatory control period.

amount of any approved expenditure, and its reasons for approving, or not approving, expenditure under the demand management innovation allowance.

As the regulatory control period progresses, this will allow the AER to collect and publish information on the nature and extent of expenditure under the DMIS.

6.2.3 Implementing the DMIS

In implementing the DMIS the AER must have regard to:

- 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 (i.e. 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
- the willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme.

The AER's likely approach to the implementation of a DMIS in ETSA Utilities' distribution determination, and its consideration of these matters, is set out in the sections that follow.

6.3 Application of the AER's proposed DMIS to ETSA Utilities

6.3.1 Operating Environment in South Australia

While South Australia's aggregate demand for electricity is not the highest in the NEM, ETSA Utilities' *Demand Management Program - Interim Report 2007* states that South Australia's 'peakiness' of demand is the highest in Australia and ranks amongst the highest in the world, with approximately one third of network capacity required for only 1 per cent to 2 per cent of the year.[209] This is largely attributed to a climate characterised by hot, dry summers, driving the summer air-conditioning needs of residential customers.

In its *2005–10 Electricity Distribution Price Determination* (EDPD)[210]for ETSA Utilities, the Essential Services Commission of South Australia (ESCOSA) provided an operating expenditure (opex) allowance of $20.4 million to fund a range of pilot demand management programmes and initiatives over the 2005–10 regulatory control period.[211] The range of approved demand management initiatives were selected on the basis of a detailed cost-benefit analysis undertaken for ESCOSA by Charles River

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209 ETSA Utilities Demand Management Program - Interim Report June 2007 report, p. 11.

210 The Essential Services Commission of SA's final decision on this matter is outlined in Chapter 4 of its decision, available at http://www.escosa.sa.gov.au.

211 Essential Services Commission of SA *2005-2010 Electricity Distribution Price Determination Part A: Statement of Reasons* April 2005, pp. 53 and 60.

Associates (CRA).[212] Under the EDPD, ETSA Utilities was required to submit a comprehensive scope of initiatives and detailed work plan for approval by ESCOSA[213]. This work plan encompassed the following areas identified in the CRA report:

- residential demand management (direct load control)
- embedded generation
- power factor correction
- load limitation
- aggregation
- critical peak pricing

ETSA Utilities has commenced a number of pilot demand management programs in these areas within the current regulatory period.

ETSA Utilities is required, as a condition of its distribution licence issued pursuant to Part 3 of the *Electricity Act 1996* (SA), to investigate the use of demand management as a means of deferring the need for significant expansions or augmentations of its distribution network in areas where the network is becoming constrained.[214]

In 2003, ESCOSA developed its Electricity Industry Guideline No. 12, "Demand Management for Electricity Distribution Networks", specifying the steps to be taken by ETSA Utilities in order to satisfy the demand management obligations placed on it under its licence.[215] Those steps include:

- annual publication of an Electricity System Development Plan which details expected network constraints over the next 3 years;

- consulting with interested parties on demand management alternatives for all network extensions and augmentations with an estimated capital cost of over $2 million.

The objective of Guideline No 12 is to improve the transparency and robustness of ETSA Utilities' demand management obligations.

During 2006/07, ESCOSA completed a review of Guideline 12. The purpose of the review was to assess whether or not the Guideline was achieving its objectives and to identify opportunities for improving its effectiveness. As a result of the review, ESCOSA has amended the Guideline to ensure that adequate information is provided by ETSA Utilities to all interested parties to facilitate demand management initiatives,

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212 CRA, *Assessment of Demand Management and Metering Strategy Options* August 2004 pp. 76-83.

213 ETSA Utilities *Demand Management, The Way Forward, 2005/06 - 2009/10,* October 2005.

214 ETSA Utilities Distribution Licence, clause 14 available at (http://www.escosa.sa.gov.au/webdata/resources/files/071107-D-ETSAUtilitiesElecDistLicence.pdf)

215 ESCOSA, *Electricity Industry Guideline Number 12: Demand Management for Electricity Distribution Networks,* July 2007 available at http://www.escosa.sa.gov.au/webdata/resources/files/070628-O-Guideline12-DemandManagementV2_Final.pdf .

but also to encourage a better interaction between customers and ETSA Utilities when considering alternatives to network augmentation.

6.3.2 Consideration of NER criteria

In applying its demand management incentive scheme for ETSA Utilities, the AER must have regard to the five factors outlined in section 6.2.3 above.

6.3.2.1 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 period where benefits are unlikely to be revealed until later periods.

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 will coordinate with both existing and potential demand management initiatives already being carried out by ETSA Utilities in the current regulatory period. As South Australia is the highest peaking state in Australia, a scheme which targets both broad-based and peak demand reduction across the distribution network is considered appropriate.

Given that South Australia's peak demand is a key driver of network capital expenditure, a demand management innovation allowance could also be used for initiatives which result in a more efficient use of existing infrastructure and a lower level of investment in new infrastructure through either deferral of, or removal of the need for, network augmentation and/or expansion expenditures.

The demand management innovation allowance is a modest scheme, provided on a 'use it or lose it' basis. Consequently increases in customer prices are expected to be minimal.

6.3.2.2 The effect of a particular control mechanism (i.e. price – as distinct from revenue – regulation) on a DNSP's incentives to adopt or implement efficient non-network alternatives

The proposed demand management innovation allowance is compatible with a range of control mechanisms, and as such is not constrained by the AER's decision on the form of control to apply to ETSA Utilities.

The AER considers that the application of its proposed demand management innovation allowance to ETSA Utilities is appropriate as it is a simple, modest scheme that is unlikely to negatively interact with other elements and incentive schemes within the regulatory framework.

6.3.2.3 The extent the DNSP is able to offer efficient pricing structures

In applying the AER's proposed DMIS to ETSA Utilities, the AER must have regard to the extent that ETSA Utilities is 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 to supply electricity in times of peak demand.

The AER considers that there is scope within the framework set out in chapter 6 of the NER for ETSA Utilities to provide efficient pricing structures, for instance in the application of peak tariffs or time-of-use tariffs to a DNSP's large customers. However, constraints on pricing structures, in particular for small customers, continue to exist. This is partly due to the failure of price signals to reach small customers, which may be addressed by the roll-out of smart meters currently being considered by the Ministerial Council on Energy (MCE). The AER also notes the requirement that the AER, in making its distribution determination for, or approving a pricing proposal from, ETSA Utilities for the purposes of the NER, must ensure that the prices charged to small customers for network services in relation to distribution services in South Australia are not subject to variation on the basis of location.[216]

The AER considers that the application of a demand management innovation allowance will provide incentives for ETSA Utilities to trial tariff-based demand management programs which will provide further information on mechanisms for efficient pricing.

6.3.2.4 The possible interaction between a DMIS and other incentive schemes

In applying its DMIS to ETSA Utilities the AER must have regard to the interaction of that scheme with the incentives created by other incentive schemes. As outlined in chapters four and five of this paper, the AER's preliminary position is that both an EBSS and STPIS will be applied to ETSA Utilities in the 2010-15 regulatory control period.

Increased expenditure on demand management within the regulatory control period may increase opex 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 AER's EBSS excludes costs associated with demand management from the calculation of opex overspends and underspends.

The incentive created by the DMIS is for ETSA Utilities to develop and implement demand side management in response to network issues.

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 targets will not be met. The DMIS operates to reduce the perceived risk by encouraging DNSPs to build their demand

[216] *National Electricity (South Australia) Act 1996*, s. 18(5)(a)

management capacity and to develop and implement viable demand management strategies.

The AER considers that the application of its proposed demand management innovation allowance to ETSA Utilities will not negatively interact with the incentives created by other incentive schemes or send conflicting signals in terms of desired expenditure outcomes.

6.3.2.5 The willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme.

The costs associated with the application of the DMIS to ETSA Utilities should be commensurate with the value South Australian customers, or end users, attach to demand management. While studies to date indicate that customers are supportive in principle of demand management initiatives, little is known about their willingness to pay. As such, a degree of judgment on the basis of expected long term benefits is required in consideration of this matter.

The AER considers that the application of its proposed DMIS is appropriate in light of the limited information available to date on customer willingness to pay for demand management, as the scheme provides a modest, capped allowance for demand management initiatives and is unlikely to result in large increases in customer prices.

6.3.3 AER's preliminary position on the application of a DMIS to ETSA Utilities

The AER's preliminary position is that it will apply a DMIS in the form of a demand management innovation allowance to ETSA Utilities for the 2010-15 regulatory control period.

The allowance will be capped at a total of $3 million over the regulatory control period, nominally allocated in five equal instalments of $600,000. The AER considers that this allowance will allow ETSA Utilities to carry out a number of small-scale demand management projects, or a single larger-scale demand management project, in each year of the regulatory control period.

The AER considers it appropriate that the primary source of funding for demand management in the forthcoming regulatory control period should be the forecast opex and capex allowances approved in the distribution determination. The demand management innovation allowance will be provided in addition to any opex and capex allowances for demand management projects included within the AER's distribution determination for ETSA Utilities. The demand management innovation allowance aims to encourage and facilitate the pursuit of demand management options within the regulatory control period that are unforseen at the time of the AER's determination.

In forming this position, the AER has had regard to the maters identified in cl. 6.6.3 of the NER, and considers that:

- The modest, use-it-or-lose it nature of the scheme is appropriate given the limited information available on customer willingness to pay for demand management[217], and the long-term nature of expected benefits arising under the scheme[218].

- Application of the scheme is not dependent on the form of control applied in the distribution determination, and is designed to operate within the pricing structures available under any form of control[219], and the ability to send efficient signals through pricing under the broader regulatory framework.[220] [221]

- The interaction between the proposed DMIS, the EBSS and STPIS is contemplated in the design of those schemes. The EBSS excludes costs associated with demand management from the calculation of opex overspends and underspends. The perceived disincentive to implement non-network alternatives to augmentation created by the STPIS is balanced by the incentive created by the DMIS to investigate and implement viable and efficient non-network solutions.

[217] NER, cl. 6.6.3(b)(5)
[218] NER, cl. 6.6.3(b)(1)
[219] NER, cl. 6.6.3(b)(2)
[220] NER, cl. 6.6.3(b)(3)
[221] NER, cl. 6.6.3(b)(4)

7 Other matters

7.1 Introduction

In addition to the components required under the NER, the AER can set out in its framework and approach paper its likely approach (together with its reasons for the likely approach) to any other matter on which the AER thinks fit to give such an indication.[222]

The matters addressed in this chapter have been identified as requiring particular clarification in advance of the submission of ETSA Utilities' regulatory proposal and the distribution determination process.

In the following sections, this chapter sets out the AER's preliminary position on its likely approach to:

- the transition from pre-tax to post-tax regulation (section 7.2)
- recognition of carryovers accrued under the efficiency carryover mechanism applied in ETSA Utilities' 2005-10 EDPD (section 7.3)

7.2 Transition from pre-tax to post-tax

7.2.1 Introduction

Chapter 6 of the National Electricity Rules (NER) requires that DNSPs be regulated using a post-tax approach. In its current and previous regulatory control periods, ETSA Utilities has been regulated using a pre-tax approach. The AER must therefore effect a transition from pre-tax to post-tax regulation as part of its distribution determination for the next regulatory control period. This section sets out the AER's likely approach to that transition.

The AER considers that the framework and approach process can be used a first step in the transition process. On completion of the framework and approach process, it is expected that information requirements relating to the application of a post-tax approach will be included as a part of a Regulatory Information Notice detailing the information that ETSA Utilities must provide in its regulatory proposal to the AER on 31 May 2009. This approach is similar to the approach taken in the NSW/ACT transition process.

The difference between a pre-tax and post-tax weighted-average cost of capital (WACC) is how tax is treated. A pre-tax WACC provides for an allowance in the WACC to account for a regulated firm's tax liability. Under a post-tax WACC approach an allowance for tax liability is included as a separate building block and forms part of the cash flows that make up the building block components – tax is not included in the return on capital or WACC building block component.

If adjustments for depreciation, interest expenses, capital contributions and inflation were made to the effective tax rate for the pre-tax WACC then the difference for the

[222] NER, cl. 6.8.1(b)(5)

revenue allocated for tax liability would be similar under either approach. However, jurisdictional regulators have traditionally applied an effective tax rate based upon corporate tax rates (without any adjustments) which may have resulted in allowances for tax which depart from the typical effective tax rate (either higher or lower) than that of a benchmark Distribution Network Service Provider (DNSP).

7.2.2 Requirements of the National Electricity Law and Rules

The post-tax revenue model (PTRM) developed by the AER in accordance with the NER[223] was published on 30 June 2008.[224] The elements of the PTRM as required by the NER are listed in section 7.2.3 of this paper. This model provides the basis for establishing the regulatory revenue requirement for DNSPs.

The jurisdictional derogation for South Australia in chapter 9, Part D of the NER requires that the AER's distribution determination for ETSA Utilities for the regulatory control period commencing on 1 July 2010 must incorporate appropriate transitional arrangements to take into account the change from a pre-tax to a post-tax revenue model. These transitional arrangements must be consistent with any agreement between the AER and ETSA Utilities about the arrangements necessary to deal with the transition.[225]

The preliminary position presented in this paper should not be construed as an agreement between the AER and ETSA Utilities. No such agreement has been made. This section sets out the AER's preliminary position on its likely approach to the transition of ETSA Utilities from a pre-tax to post-tax revenue model. The AER considers it appropriate to give an indication of its likely approach to the transition from a pre-tax to a post-tax revenue model at this time, to enable interested stakeholders to provide views on how such a transition should be made. Any agreement reached by the AER and ETSA Utilities will take such views into account.

Chapter 9, Part D of the NER requires that the AER determine the amount a South Australian DNSP may receive by way of capital contributions, prepayment and/or financial guarantee in respect of a South Australian network.[226] Issues relating to the estimation and treatment of capital contributions are discussed in section 7.2.3.2 of this paper.

7.2.3 Elements of the post-tax revenue model

The PTRM forms a part of the building block calculations with respect to the estimation of the cost of corporate income taxes. Revenue proposals submitted by DNSPs must be prepared in accordance with the PTRM. Chapter 6, Part C of the NER states that the PTRM must include at least:

- a method that the AER determines is likely to result in the best estimates of expected inflation

[223] NER, cl. 6.4.1
[224] The post-tax model was published on the same date as this preliminary positions paper. The post-tax revenue model can be found on the AER website (http://www.aer.gov.au/content/index.phtml/itemId/709250).
[225] NER, cl. 9.29.5(b)(1)
[226] NER, cl. 9.29.6

- the timing assumptions and associated discount rates that are to apply in relation to the calculation of the building blocks
- the manner in which working capital is to be treated and
- the manner in which the estimated cost of corporate income tax is to be calculated.[227]

The following section sets out preliminary positions on a number of key issues to facilitate transitional arrangements from a pre-tax to post-tax approach. These issues relate to the estimation of the tax asset base and (economic and tax) depreciation, treatment of capital contributions, timing assumptions for capital expenditure and depreciation, and carried-forward tax losses.[228]

7.2.3.1 Estimation of the initial tax asset base

In order to estimate the tax liability faced by a regulated entity for any given year the amount of tax depreciation needs to be estimated. Estimation of the amount of tax depreciation available to ETSA Utilities in the next regulatory control period will require:

- the selection of a starting point from which to value the tax asset base and a valuation methodology
- reconciliation of the tax asset base and the regulatory asset base (RAB), broken up into asset classes (sum and depreciation method), and standard and alternative control services in separate tables with assets recorded in the financial statements
- the inclusion of work-in-progress in the tax asset base (if an as-incurred approach is adopted) and
- where applicable, reconciliation of the changes in the tax asset base and the RAB in previous control periods.

Several factors need to be considered prior to selecting a starting point for the tax asset base. These include the age of the regulated assets, the prevailing tax laws throughout the period, changes in the regulation of ETSA Utilities and the privatisation of ETSA Utilities.

Given that there were a number of transition phases between ETSA Utilities being corporatised and then separated to be sold at the end of December 1999,[229] the AER considers that the date of privatisation is likely to be an appropriate starting point. The AER will consider an earlier starting point if ETSA Utilities can demonstrate that it can reconcile its tax asset base to an earlier point in time.

The AER will work with ETSA Utilities to ensure that the tax asset values on commencement of the post-tax approach are reasonable and appropriately substantiated.

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[227] NER, cl. 6.4.2.

[228] For further information relating to the AER's fuller consideration of issues associated with the transition of energy businesses to post-tax regulation you can also refer to the AER Issues Paper and Decision documents relating to the NSW/ACT electricity distribution guideline process (Refer to <http://www.aer.gov.au/content/index.phtml/itemId/717017>) .

[229] SA Auditor-General, *Report of the Auditor-General for the Year Ended 30 June 2000 – Part B - Agency Audit Reports*, <http://www.audit.sa.gov.au/99-00/b3/esi-d-resiutil.htm>, 4 October 2000, viewed 9 April 2008.

7.2.3.2 Depreciation

The AER considers that the straight-line depreciation method is a rule compliant approach, although the AER will assess the depreciation schedules proposed by ETSA Utilities against the requirements of cl. 6.5.5 of the NER. To the extent that ETSA Utilities proposes a depreciation method other than straight-line depreciation, the AER will require ETSA Utilities to explain how the alternative method satisfies the requirements in cl. 6.5.5.

The AER notes that where the PTRM calculates forecast depreciation for capex based on a particular method (e.g. straight-line), under cl. S6.2.3(c)(2) of the NER the roll-forward model (RFM) would use the same depreciation method based on actual capex. If the AER accepts an alternative method, the RFM used subsequently must also incorporate this method.

7.2.3.3 Capital contributions in the current and previous regulatory control period

Capital contributions are assessed as revenue for tax purposes, with a tax asset being created at the time of the contribution which can be depreciated over future years. Contributions received prior to the forthcoming regulatory control period will not be included in the tax asset base as:

- capital contributions have not been included in the RAB historically
- including capital contributions would create a shortfall given that past contributions have not been indexed, and
- the tax assets received from capital contributions compensated ETSA Utilities for the corporate tax incurred from receiving them.

7.2.3.4 Capital contributions during the forthcoming control period

Capital contributions are excluded from the RAB as the DNSP does not incur financing expenses from contributed capital. Capital contributions need to be included in the PTRM, however, as they are considered a form of revenue for tax purposes. Further, capital contributions are treated as depreciating assets for tax purposes, which reduces a DNSP’s tax liability.

For the purposes of consistency with the previous regime the AER’s preliminary position is that ETSA Utilities should be allowed to continue to forecast capital contributions using a similar approach to that used in the current regulatory control period. This approach involves ETSA Utilities forecasting the amount of capital contributions[230] based upon forecast augmentations and connections. At the time of the distribution determination, the AER will then determine whether the forecasts provided by ETSA Utilities meet the NER requirements for forecast capital expenditure and capital contributions.[231]

[230] The forecast amount will be based upon an estimation of the amount of augmentations and connections that require customer contributions as defined in sections 3.5 and 3.6 of the South Australian Electricity Distribution Code.
[231] NER, cl. 6.21, cl. 6.5.7, and cl. 9.29.6.

7.2.3.5 Timing assumptions

Under the as-incurred approach all forecast expenditure is recognised as it is incurred. Under the hybrid approach capital expenditure (and subsequently depreciation) is recognised when it is commissioned, and all under-expenditure is recognised as-incurred.

The AER recognises that by adopting the as-incurred approach there is a trade-off between an overstatement in depreciation and the regulatory costs involved in changing to a hybrid approach. It is likely that ETSA Utilities' capital expenditure program will involve a large number of small projects, relative to transmission network service providers who are involved in a small number of large projects. The AER considers that changing to a hybrid approach would have little impact on tax depreciation while increasing the complexity of the PTRM unnecessarily. Therefore the AER concludes that the regulatory cost associated with the hybrid approach outweighs the benefit of reducing the likelihood of overstated depreciation.

The AER's preliminary position is that the timing of capital expenditure in the PTRM submitted by ETSA Utilities should be recognised on an as-incurred basis, rather than under a hybrid approach.

7.2.3.6 Carried-forward tax losses

Under Australian tax law companies are allowed to carry forward tax losses sustained in previous periods to offset tax expenses in current periods. Therefore in order to estimate the expected tax expense, tax losses need to be considered. ETSA Utilities' recent financial statements suggest that it is unlikely that ETSA Utilities has sustained tax losses in the current or previous regulatory control period. As at 31 December 2006, ETSA Utilities recorded a profit before income tax of $142.3 m, and a net profit of $136.9 m.[232] Therefore the AER proposes that tax losses will be set to zero in the PTRM.

7.2.3.7 Other issues

The AER recognises that the above issues relating to the transition from a pre-tax to a post-tax approach are not an exhaustive list. In order to estimate a tax building block the AER will be ensuring that in ETSA Utilities' regulatory proposals, that:

- disposals during the control period are accounted for in the tax asset base
- asset classes are grouped in manner that can be reconciled against the tax asset base and
- the X-factor used is consistent with the control formula.

[232] ETSA Utilities, *2006 Annual Report – 2006 Results Summary*, 29 March 2007, p. 12.

7.3 Transitional arrangements – 2005-10 EDPD

7.3.1 Efficiency carryover mechanism

Clause 7.4 of the *Electricity Pricing Order* permits ESCOSA to issue a Statement of Regulatory Intent (SORI) setting out how it will exercise its powers under chapter 7 of the *Electricity Pricing Order*.

On 23 March 2007 ESCOSA issued a SORI setting out transitional arrangements in relation to the efficiency carryover mechanism in its 2005-10 EDPD.[233]

The jurisdictional derogation for South Australia in chapter 9 of the NER provides that the efficiency benefit sharing scheme (EBSS) applied by the AER under its distribution determination for ETSA Utilities for the forthcoming regulatory control period must be consistent with the statement of regulatory intent.[234]

The SORI states that:

> [ESCOSA's] intent is that any net negative efficiency amount calculated under the current period efficiency carryover mechanism will not be carried forward as a zero amount, and will be carried over as a negative amount. However, the decision to apply a negative carryover amount in respect of the current period efficiency carryover mechanism, or to defer a negative carryover amount to offset any future positive carryover amount, may be subject to discretion by the [AER]. [235]

The SORI does not limit the AER's discretion in the development or implementation of its own EBSS, which is discussed in chapter 5 above. The effect of the SORI is that the AER must apply carryovers to ETSA Utilities as intended by ESCOSA in its existing efficiency carry-over mechanism relating to the current regulatory period. That is, that any relevant efficiency gains, negative or positive, from the current efficiency benefit sharing scheme administered by ESCOSA should be included for the purposes of calculating forecast opex and capex at the outset of the forthcoming regulatory control period.

For efficiency gains realised in the current regulatory period, each annual carryover amount for the current regulatory period will calculated and used in the building block determination for the forthcoming regulatory control period. The AER will incorporate all negative and positive carryover amounts accrued in any year of the current regulatory period into forecast opex amounts for the forthcoming regulatory period. Although the AER does not include capex in its EBSS, capex efficiency carryovers that have been realised in the current regulatory period will be included in the capex forecasts for ETSA Utilities in the forthcoming regulatory control period.

The SORI allows the AER the discretion to defer a negative carryover amount to offset any future positive carryover amount. The AER will consider the desirability of

[233] *Electricity Pricing Order Clause 7.4 – Statement of Regulatory Intent: Electricity Distribution Efficiency Carryover Mechanism.* http://www.escosa.sa.gov.au/webdata/resources/files/070323-D-ECM-StatementRegulatoryIntent.pdf

[234] NER, cl. 9.29.5

[235] *Electricity Pricing Order Clause 7.4 – Statement of Regulatory Intent: Electricity Distribution Efficiency Carryover Mechanism.* http://www.escosa.sa.gov.au/webdata/resources/files/070323-D-ECM-StatementRegulatoryIntent.pdf

deferring any accumulated negative carryover amount when the magnitude of any such amount is known.

Appendix A: Current classification of distribution services

This section contains ETSA Utilities' service classifications for the 2005-10 regulatory control period. These classifications are reproduced from the 2005-10 Electricity Distribution Price Determination (EDPD)[236], which was determined by the Essential Services Commission of South Australia (ESCOSA) in accordance with the National Electricity Code (NEC).

Italicised terms are defined in the EDPD. The more significant of these defined terms are reproduced below.

Distribution services

Distribution services means either or both of:

b. all services provided by a *distribution system* or *ETSA Utilities* which are associated with the conveyance of electricity through the *distribution system* including, without limitation, *connection services*, *network services*, *metering services*, *entry services*, *distribution network use of system services*, *exit services*, and *network services* which are provided by part of a *distribution system*;

c. all services associated with the establishment and operation or *retailer of last resort* capabilities by *ETSA Utilities* in accordance with the *retailer of last resort requirement* of *ETSA Utilities' distribution licence*, other than services charged for by *ETSA Utilities* as *excluded services* in accordance with clause 1.9(a) of the *Excluded Services Schedule*.

Prescribed distribution services

Prescribed distribution services means *distribution services* other than *excluded services*.

Excluded services

Excluded services means the services provided by *ETSA Utilities* set out in the *Excluded Services Schedule* in respect of which the *Commission* has price determination powers under the *ESC Act* and a more light handed approach to price regulation is taken.

Excluded Services Schedule means Schedule 1.

Schedule 1 of the EDPD – Excluded services schedule

7. **Public lighting**

[236] ESCOSA, *2005-2010 electricity distribution price determination – part B – price determination*, April 2005.

d. Public lighting services including:

iii. operation and maintenance of public lighting; and

iv. provision of public lighting assets.

8. **New and upgraded connection points**

e. The:

v. provision of a new *connection point*, including associated extension or augmentation of the *distribution network*; or

vi. upgrading of the capability of a *connection point*, including by extension or augmentation of the *distribution network*,

to the extent that a *distribution network user* is required to make a financial contribution in accordance with the *Electricity Distribution Code*.

f. Responding to an enquiry in relation to a *connection point* referred to in paragraph 1.2(a)(i).

g. Providing technical specifications in relation to a *connection point* referred to in paragraph 1.2(a)(ii).

9. **Service standards**

h. The provision of *network services* or *connection services*, at the request of a *distribution network user*:

vii. with higher quality or reliability standards than are required by the *Code*, the *Electricity Distribution Code*, the *Electricity Metering Code* or any other *applicable laws*; or

viii. in excess of levels of service or plant ratings required to be provided by *ETSA Utilities'* assets.

10. **Stand-by and temporary supply**

i. The following services associated with stand-by and temporary supply:

ix. provision of electric plant for the specific purpose of enabling the provision of top-up or stand-by supplies or sales of electricity;

x. provision of network services for a *connection point* where a *distribution network user* operates parallel generation requiring a stand-by supply;

xi. provision of temporary supplies; and

xii. provision of reserve (duplicate) supply.

11. **Distribution system**

j. Moving mains, services or *meters* forming part of the *distribution system*, providing temporary disconnection, or temporary line insulation to accommodate extensions, re-design or re-development of any premises or otherwise as requested by a *distribution network user*.

12. **Metering services**

k. In relation to *small distribution network users*, the provision of *metering services*:

xiii. at all *first tier connection points* and *second tier connection points* where a *meter* meeting the requirements of a *metering installation type 1, metering installation type 2, metering installation type 3, metering installation type 4, metering installation type 5M* or *metering installation type 5R* is or is to be installed to the extent that the charges for such *metering services* exceed the charges for the provision of *metering services* in respect of a *meter* meeting the requirements of a *metering installation type 6* or *metering installation type 7*;

xiv. in respect of *meters* meeting the requirements of a *metering installation type 6* and *metering installation type 7* containing a *meter* different to the type of *meter ETSA Utilities* would ordinarily install (including *prepayment meter systems*), which *meter* is installed at the request of a *retailer* or a *distribution network user*, but only to the extent that the charges for such *metering services* exceed the charges for the provision of *metering services* in respect of *metering installations types 6* and *metering installations type 7* containing a *meter* of a type that *ETSA Utilities* would ordinarily install.

l. In relation to *distribution network users* other than those specified in Schedule 1.6(a), all *metering services* except:

xv. *meter provision services* provided in respect of *meters* meeting the requirements of *metering installation type 1, metering installation type 2, metering installation type 3* or *metering installation type 4* installed prior to 1 January 2000; and

xvi. *meter provision services* provided in accordance with the requirement of clause 27 of *ETSA Utilities'* distribution licence as in force at 30 June 2005.

m. In relation to *metering data services*, the provision of special meter readings and associated services.

13. Electricity Distribution and Electricity Metering Codes

n. The following services provided in connection with the *Electricity Distribution Code* and the *Electricity Metering Code*:

xvii. application for an account or new supply;

xviii. provision of a copy of the *Electricity Distribution Code* or the *Electricity Metering Code*;

xix. provision of old billing data;

xx. *meter* testing at the request of a *distribution network user*;

xxi. after-hours reconnection;

xxii. reconnection due to a *distribution network users'* fault; and

xxiii. disconnection services provided to a *retailer*, or a *distribution network user*.

14. Embedded generation

o. Services and system augmentation or extension required to receive energy from an *embedded generator* and meet the requirements of the *Code*.

15. **Retailer of last resort**

p. The sale of electricity to customers of another electricity entity in accordance with the *retailer of last resort obligation* in *ETSA Utilities'* electricity distribution licence.

16. **Other services**

q. Provision of reactive power and energy to a *connection point* or receipt of reactive power and energy from a *distribution connection point*;

r. investigation and testing services;

s. asset location and identification services;

t. the transportation of electricity not consumed in the *distribution system*;

u. the transportation of electricity to *distribution network users* connected to the *distribution system* adjacent to the *transmission system*;

v. repair of equipment damaged by a *distribution network user* or a third party

w. provision of

   xxiv. high *load* escorts;

   xxv. measurement devices;

   xxvi. protection systems;

   xxvii. pole attachments;

   xxviii. ducts and conduits; and

x. any other *distribution service* requested by *distribution network users* or other parties which the *Commission* considers is reasonable contestable and accordingly, should be regulated as an *excluded service*.

Definitions

Connection services means either or both of the:

y. provision of capability at each *connection point* (by means of the *connection assets* for the *distribution connection point*) to deliver electricity to or take electricity from the *connection point* using *connection assets*;

z. management, maintenance and operation of *connection assets*, so as to provide the capability referred to in paragraph (a) of this definition,

using *good electricity industry practice* and in accordance with the requirements of the *Code*, the *Electricity Distribution Code*, the *Electricity Metering Code* and any other *applicable laws*.

Distribution network use of system services means services provided to a *distribution network user* for use of the *distribution network* for the conveyance of electricity than can be reasonably allocated on a locational and/or voltage basis.

Distribution system means the apparatus, equipment, plant and buildings use to convey, and control the conveyance of electricity to *distribution network users* including any *connection assets*, and, in respect of *ETSA Utilities* means the *distribution system* that *ETSA Utilities* has a distribution licence under the *Act* to operate, or in respect of which *ETSA Utilities* is exempt from obtaining such a licence.

Entry services means a distribution service provided to serve a *generator* or group of *generators* at a *single connection point*.

Exit services means a service provided to serve a *distribution network user* or group of *distribution network users* at a *single connection point*.

Metering services means *meter provision services* and *metering data services*.

Meter provision services means the supply, installation and maintenance of *metering installations*.

Metering data services means the collection, processing and storage of, and provision of access to, *energy data*.

Network services means each or all of:

aa. the provision of *network capability* to support the delivery of electricity to *distribution connection points* up to the *agreed maximum demand* for the *connection point* (where applicable) or otherwise at the level of demand at which electricity is generally delivered to or taken from the *distribution connection point*;

bb. the management, maintenance and operation of the *distribution network* to provide the *network capability* referred to in paragraph (a) of this definition; and

cc. such additional activities as are necessary to ensure the integrity of the *distribution network* and maintain the *network capability* to support the delivery of electricity to and, where applicable, to take electricity from, *distribution connection points,*

using *good electricity practice* and in accordance with the requirements of the *Code*, the *Electricity Distribution Code* and any other *applicable laws*.

Retailer of last resort requirement has the meaning given to it in the *Act*.

Glossary

ADR	Average Distribution Revenue
AER	Australian Energy Regulator
capex	capital expenditure
cl. / cll.	clause / clauses
CLER	customer lighting equipment rate
CPI	Consumer Price Index
CPI-X	CPI minus X
CRA	Charles River Associates
DMIS	Demand management incentive scheme
DNSP	Distribution Network Service Provider
DUOS	distribution use of system
EBSS	Efficiency benefit sharing scheme
EDC	Electricity Distribution Code
EDPD	Electricity Distribution Price Determination
EPO	Electricity Pricing Order
ESCOSA	Essential Services Commission of South Australia
ESCV	Essential Services Commission of Victoria
ETSA	Electricity Trust of South Australia
FADR	Forecast average distribution revenue
FDE	Forecast distributed electricity
GSL	Guaranteed service level
ICB	Initial Capital Base
LGA	Local Government Association of South Australia
m	million
MADR	Maximum average distribution revenue
MAIFI	Momentary average interruption frequency index
MCE	Ministerial Council on Energy

MWh	Megawatt hours
NEC	National Electricity Code
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
OMS	Outage Management System
opex	operating and maintenance expenditure
PTRM	Post-Tax Revenue Model
QLD	Queensland
RAB	Regulatory Asset Base
RFM	Roll-Forward Model
ROLR	retailer of last resort
s.	section
SA	South Australia
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCONRRR	Steering Committee on National Regulatory Reporting Requirements
SLUOS	street lighting use of system
STPIS	Service target performance incentive scheme
VCR	Value Customer Reliability
WACC	Weighted Average Cost of Capital