Final

Framework and approach paper

ETSA Utilities 2010-15

November 2008

Contents

Summary

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. 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, and commenced on 30 June 2008. During that time, the Essential Services Commission of South Australia (ESCOSA) will remain responsible for administration of the Electricity Distribution Price Determination (EDPD) for the regulatory control period 1 July 2005 to 30 June 2010.

In anticipation of every distribution determination, the AER is required to prepare and publish a framework and approach paper:

- 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.

This is the AER's framework and approach paper for ETSA Utilities. Each element of the paper is summarised below, and discussed in detail in the chapters that follow.

Classification of services

In classifying distribution services provided by ETSA Utilities, the NER require 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

- (if there has been no previous classification) the classification should be consistent with the previously applicable regulatory approach,

unless a different classification is clearly more appropriate.

In this case, this requirement gives rise to a presumption that in the forthcoming regulatory control period:

- ETSA Utilities' current prescribed distribution services should be classified as direct control services, and further classified as standard control services, and

- ETSA Utilities' current excluded services should be classified as negotiated distribution services.

Having had regard to the requirements of the NEL and the NER, the AER's likely approach is to classify network services, connection services, public lighting services and 'other' distribution services in accordance with this presumption. No other approach to classification of these services is clearly more appropriate.

The AER is likely, however, to depart from the regulatory approach in the current period in respect of the following services:

- The AER does not consider that pole and duct rental for non-electricity (e.g. telecommunications) purposes falls within the definition of distribution service under the NER. These services can not be classified under chapter 6, and consequently can not be regulated under the NER.

- The AER's likely approach is to classify 'standard' small customer metering services (type 6 metering installations) as direct control services (consistent with the previously applicable regulatory approach), but then to further divide these services into:

  - 'fixed' standard small customer metering services (type 6 metering installations) as standard control services, and

  - 'variable' standard small customer metering services (type 6 metering installations) as alternative control services.

  The AER considers that such an approach is more appropriate, as it would effectively 'unbundle' the charges for these services from DUOS charges, removing existing barriers to entry in metering services markets and leading to more cost reflective price outcomes.

- For legacy reasons, the AER also considers it more appropriate to classify two exceptional cases of large customer metering services (types 1-4 metering installations) as alternative control services than standard control services. Classification in this way is expected to achieve a more cost reflective outcome.

The AER considers the remaining metering services should be classified in a manner which is consistent with the previously applicable regulatory approach so that, as outlined in the preliminary positions paper, its likely approach is to:

- classify 'non-standard' small customer metering services (meters meeting the requirements of type 1-4 metering installations provided to small customers, and type 5 metering installations) as negotiated distribution services,

- classify all large customer metering services (type 1-4 metering services provided to large customers) as negotiated distribution services, and

- classify unmetered metering services (type 7 metering installations) as direct (standard) control services.

The AER considers that services associated with ETSA Utilities' current role as the South Australian retailer of last resort (which expires on 30 June 2010) fall outside the NER definition of distribution services, and is therefore unable to classify those services under chapter 6 of the NER.

Control mechanisms

A distribution determination imposes controls on the prices of direct control services, the revenue to be derived from direct control services, or both. This framework and approach paper must state the form or forms of control mechanisms to be applied to ETSA Utilities' direct control services for the forthcoming regulatory control period. Unlike other elements of this framework and approach paper, the form or forms of control in this paper are binding for the relevant distribution determination.

Standard control services

The preliminary position was that there should be no departure from the previous form of control mechanism applied to standard control services, which was a variant of an average revenue cap (revenue yield), unless a different approach was clearly more appropriate.

In response to the preliminary position, ETSA Utilities proposed a transition to a weighted average price cap (WAPC) for the 2010-15 regulatory control period.

Having considered ETSA Utilities' submission with regard to the requirements of cl. 6.2.5 of the NER, the AER has concluded that there are clear grounds on which to adopt a WAPC in place of the current form of control. A transition to a WAPC will generate benefits to both ETSA Utilities and its customers, including the greater likelihood of efficient tariff structures, and improved risk and incentive properties relative to the current form of control.

The AER's distribution determination will therefore apply a WAPC to ETSA Utilities' standard control services in the 2010-15 regulatory period.

Alternative control services

On the basis of the AER's likely approach to classification of 'variable' standard small customer metering services and exceptional large customer metering services as alternative control services, ETSA Utilities will also be required to apply a WAPC form of control to those services. This form of control is considered best suited for the unbundling of ETSA Utilities' metering service charges from the DUOS tariffs, and will thereby facilitate development of competition in the market for those services. Consistency with the control mechanism applied to standard control services is expected to reduce administrative costs of introducing a separate form of control mechanism.

Application of service target performance incentive scheme

Having given full consideration to the matters identified in clause 6.6.2 of the NER, the AER's likely approach in the forthcoming distribution determination will be to apply the STPIS to ETSA Utilities. The STPIS will replace the service incentive scheme applied in the current period, and will operate in conjunction with the average service standards and the guaranteed service level (GSL) schemes administered by ESCOSA.

The AER will not apply a GSL scheme to ETSA Utilities in the 2010–15 regulatory control period whilst ETSA Utilities remains subject to a jurisdictional GSL scheme. If at any time in the forthcoming regulatory control period ESCOSA ceases to apply a GSL scheme, the AER's likely approach is to apply the GSL component of the STPIS from the date the jurisdictional scheme is withdrawn.

The AER's likely approach is to apply the reliability of supply and customer service components of the STPIS to ETSA Utilities in the forthcoming regulatory control period, in the form of an s-factor. Unplanned system average interruption duration index (SAIDI) and unplanned system average interruption frequency index (SAIFI) are likely to be applied as parameters under the reliability of supply component, and telephone answering under the customer service component. For the purposes of setting targets for SAIDI and SAIFI, the AER considers that the South Australian distribution network should be segmented according to feeder type (CBD feeder, Urban feeder, Short rural feeder, Long rural feeder).

The AER's likely approach is to place ±3% of ETSA Utilities' revenue at risk under the STPIS, and within that a cap of ±0.5% on the telephone answering parameter applied under the customer service component of the scheme. The AER is not satisfied that the lower incentive cap of ±1% of total revenue (including a maximum incentive for the customer service component of ± 0.05% of revenue) proposed by ETSA Utilities is sufficient to offset any incentives it may have to reduce costs at the expense of service levels. This conclusion has been reached having regard to ETSA Utilities' variable past performance against targets, and 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 within the greater scope of the STPIS relative to the existing service incentive scheme.

The STPIS excludes from the calculation of reliability performance any day (measured from midnight to midnight) where daily unplanned SAIDI for the electricity distribution network exceeds the major event day threshold. This threshold is currently calculated using the methodology set out in the Institute of Electrical and Electronics Engineers Standard 1306-2003 (IEEE standard) which uses the natural log to convert daily SAIDI into a normal distribution (the 2.5 beta method) to which statistical measures are applied to remove outliers in performance.

On the basis of the historical performance data provided thus far, it is possible that use of the Box-Cox methodology proposed by ETSA Utilities, in place of the mechanism in the IEEE exclusion that currently applies under the STPIS, may produce a more normal distribution of ETSA Utilities' daily SAIDI data, making it better suited to the operation of the remaining elements of the IEEE exclusion. Subject to adequate verification of the supporting data in ETSA Utilities' regulatory proposal, the AER will consider applying the Box-Cox methodology to ETSA Utilities for the purposes of distributing data for the 2010–2015 regulatory control period, if to do so would result in application of the exclusion in a way that better reflects past performance of ETSA Utilities' network.

The AER will continue to investigate the concern raised by ETSA Utilities and other parties over the potential perverse incentives that occur when performance in a scheme year is such that the cap on revenue at risk is invoked, and the solutions proposed. Any amendments to the STPIS required to address this issue will be proposed and finalised before the submission of ETSA Utilities' regulatory proposal in May 2009. Amendment of the s-factor calculation is not expected to change the likely approach to the application of the STPIS outlined in this framework and approach paper, and will not hinder ETSA Utilities' ability to submit a fully compliant regulatory proposal.

Application of efficiency benefit sharing scheme

The AER released the distribution efficiency benefit sharing scheme (EBSS) on 26 June 2008. Having given full consideration to the matters identified in clause 6.5.8(c) of the NER, the AER's likely approach is to apply the EBSS to ETSA Utilities in the forthcoming distribution determination. ETSA Utilities will be required to propose any categories of uncontrollable opex it considers should be excluded from the operation of the EBSS as part of its regulatory proposal in May 2009. ETSA Utilities must also include in its regulatory proposal details of any growth adjustment methods it submits should be applied to factor growth into its opex forecast.

In accordance with the jurisdictional derogation for South Australia and ESCOSA's statement of regulatory intent (SORI), the AER will recognise both capex and opex carryovers accumulated under the efficiency carryover mechanism administered by ESCOSA in the current regulatory period. Each annual carryover amount for the current regulatory period will be calculated and applied in the building block determination for the 2010-2015 regulatory control period. Calculation of efficiency gains or losses in the final year of the current regulatory control period will be in accordance with the mechanism for that calculation in ESCOSA's efficiency carryover mechanism.

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 is, under the SORI, subject to the AER's discretion.

The exclusion of capex from the EBSS means that the option of deferring a negative capex carryover amount accumulated under ESCOSA's efficiency carryover mechanism is not available. However, the AER will exercise its discretion to defer a net negative opex carryover having regard to the materiality of the accumulated negative carryover, and whether it was accrued, in whole or in part, in an opex category that is excluded by the EBSS but not by ESCOSA's efficiency carryover mechanism, or is an approved uncontrollable cost category under the EBSS in ETSA Utilities distribution determination for the 2010-15 regulatory control period.

Application of demand management incentive scheme

On 17 October 2008, after consultation under the NER, the AER published a DMIS to be applied to Energex, Ergon Energy, and ETSA Utilities in the regulatory control periods commencing 1 July 2010.

That DMIS consists of two parts:

- Part A – the demand management innovation allowance (DMIA), and
- Part B – the recovery of forgone revenue due to a reduction in the quantity of electricity sold as a result of demand management initiatives approved under the DMIA.

Having had regard to the requirements of cl. 6.6.3 of the NER, the AER's likely approach is to apply both parts A and B of the DMIS to ETSA Utilities for the 2010-15 regulatory control period.

The DMIA in part A of the scheme is designed to supplement a DNSP's approved capex and opex, to facilitate investigation and implementation of demand management strategies. Where these prove viable, this will allow ETSA Utilities to implement non-network alternatives where efficient, and to manage the expected demand for standard control services by means other than expansion of supply. The AER's likely approach is to make a DMIA in the amount of $3 million ($600 000 per annum) available to ETSA Utilities in the forthcoming regulatory control period.

The AER has determined that ETSA Utilities will be subject to a WAPC, which may result in its recovery of the annual revenue requirement being at least partially dependent on the amount of electricity sold. This could create disincentives for ETSA Utilities to undertake demand management strategies. To counter this disincentive, the AER is likely to apply the forgone revenue mechanism in part B of the DMIS, to allow ETSA Utilities to recover any forgone revenue directly attributable to a reduction in the quantity of electricity sold due to implementing demand management projects or programs approved under the DMIA. The recovery of forgone revenue is in addition to the capped amount of the DMIA, however the actual amount that can be recovered is limited to approved revenue forgone within the 2010-15 control period, resulting from a successful project established under part A of the scheme.

Other matters - Transition from pre-tax to post-tax revenue model

In the distribution determination for ETSA Utilities, the AER must effect a transition from the current pre-tax revenue model to the post-tax revenue model developed under chapter 6 of the NER.

While the jurisdictional derogation for South Australia allows the AER and ETSA Utilities to agree upon transitional arrangements, no agreement has been reached between the parties at this time. Nothing in this framework and approach paper should be construed as an agreement between ETSA Utilities and the AER.

In the absence of any such agreement, arrangements for the transition from pre-tax to post-tax regulation will be considered in accordance with the requirements of the NER at the time of its distribution determination for ETSA Utilities. The AER will (through a regulatory information notice) require ETSA Utilities to include in its proposal sufficient information to effect the transition from pre-tax to post-tax regulation. The transitional arrangements proposed by ETSA Utilities will then be assessed on their merits against the requirements of the NER, with regard to any submissions received.

Next steps

This framework and approach paper completes the first stage of consultation on the distribution determination for ETSA Utilities for the forthcoming regulatory control period.

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

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

* 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 Introduction

The Australian Energy Regulator (AER) is responsible for the economic regulation of electricity distribution services in the National Electricity Market (NEM). The AER's functions and powers are set out in the National Electricity Law (NEL) and the National Electricity Rules (NER). Chapter 6 of the NER sets out the AER's responsibilities in relation to the economic regulation of distribution network service providers (DNSPs), and requires the AER to make distribution determinations for DNSPs.

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 takes place over the final two years of the current regulatory period. During that time, ETSA Utilities will continue to be 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 first step in making a distribution determination is the preparation and publication of a framework and approach paper. For ETSA Utilities, this step in the process commenced on 30 June 2008 and is completed with the publication of this paper.

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.[1] 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 in 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.

[1] NER cl. 6.8.1

The framework and approach paper is not otherwise binding on the AER or a DNSP. The decision ultimately made in the AER's distribution determination for ETSA Utilities may depart from the likely approach set out in this framework and approach paper. 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[2], and
- 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 that approach would satisfy the requirements of the NEL and NER.

The framework and approach paper must also include the AER's determination as to whether or not Part J of chapter 6A of the NER is to be applied to determine the pricing of transmission standard control services provided by any dual function assets owned, controlled or operated by the DNSP.[3] If a DNSP owns, controls or operates dual functions assets, it must advise the AER of the value of those assets 24 months prior to the end of the current regulatory control period to enable such a determination.[4] This obligation came into effect on 1 July 2008, after consultation on the framework and approach paper for ETSA Utilities had commenced. ETSA Utilities has not advised the AER of any such assets, and so this framework and approach paper does not include a determination of this nature.

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

[2] NER, cl. 6.12.3(b)

[3] NER, cl. 6.8.1(ca). A dual function asset means any part of a network owned, operated or controlled by a Distribution Network Service Provider which operates between 66 kV and 220 kV and which operates in parallel, and provides support, to the higher voltage transmission network which is deemed by clause 6.24.2(a) to be a dual function asset. For the avoidance of doubt:

(a) a dual function asset can only be an asset which forms part of a network that is predominantly a distribution network; and

(b) an asset which forms part of a network which is predominantly a transmission network cannot be characterised as a dual function asset,

through the operation of clause 6.24.2(a).

[4] NER, cl. 6.25

Table 1.1 Procedure 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

* 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.

On 30 June 2008, the AER published a preliminary positions paper on its framework and approach for ETSA Utilities.

This final framework and approach paper for ETSA Utilities sets out the AER's consideration of issues raised in response to the preliminary positions paper, and sets out the framework and approach for the AER's distribution determination for ETSA Utilities for the regulatory control period commencing 1 July 2010.

1.2 Structure of this paper

This paper sets out the AER's framework and approach for ETSA Utilities for the 2010-15 regulatory control period.

- Chapter 2 sets out the likely approach to classification of distribution services provided by ETSA Utilities.
- Chapter 3 states the form of the control mechanisms to be applied to direct (standard and alternative) control services by the distribution determination.
- Chapter 4 sets out the likely approach to the application to ETSA Utilities of the service target performance incentive scheme.
- Chapter 5 sets out the likely approach to the application to ETSA Utilities of the efficiency benefit sharing scheme.

- Chapter 6 sets out the likely approach to the application to ETSA Utilities of the demand management incentive scheme.
- Chapter 7 of this paper sets out the likely approach to the arrangements for transition from a pre-tax to a post-tax revenue model.

Appendices to this paper provide details of distribution services provided by ETSA Utilities and the control mechanisms to be applied.

2 Classification of services

2.1 Introduction

This chapter sets out the 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. The AER must further classify direct control services as either standard control services or alternative control services. Services not classified are not regulated under the NER. Service classification effectively determines two key aspects of the distribution determination:

- whether the service should be under a direct price or revenue control, a 'negotiate-arbitrate' framework, or no price or revenue control – that is, the form of control that will apply to the service[5], 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.[6]

2.2 Requirements of the National Electricity Law and Rules

A distribution determination must include a decision on the classification of the distribution services to be provided by the DNSP during the course of the relevant regulatory control period.[7] Only services within the definition of distribution services contained in chapter 10 of the NER can be classified. The classification forms part of the distribution determination and operates only for the period for which the determination is made.[8]

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.[9] 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 proposed in that paper.[10]

5 The forms of control available for each service depend on the classification. This is discussed in greater detail in chapter 3 of this paper.

6 In general, the costs of providing direct control (standard control) services would be expected to be recovered through DUOS tariffs paid by all or most customers, whereas the costs of providing direct control (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.

7 NER, cl. 6.12.1(1)

8 NER, cl. 6.2.3

9 NER, cl. 6.8.1(b)(1)

10 NER, cl. 6.12.3(b)

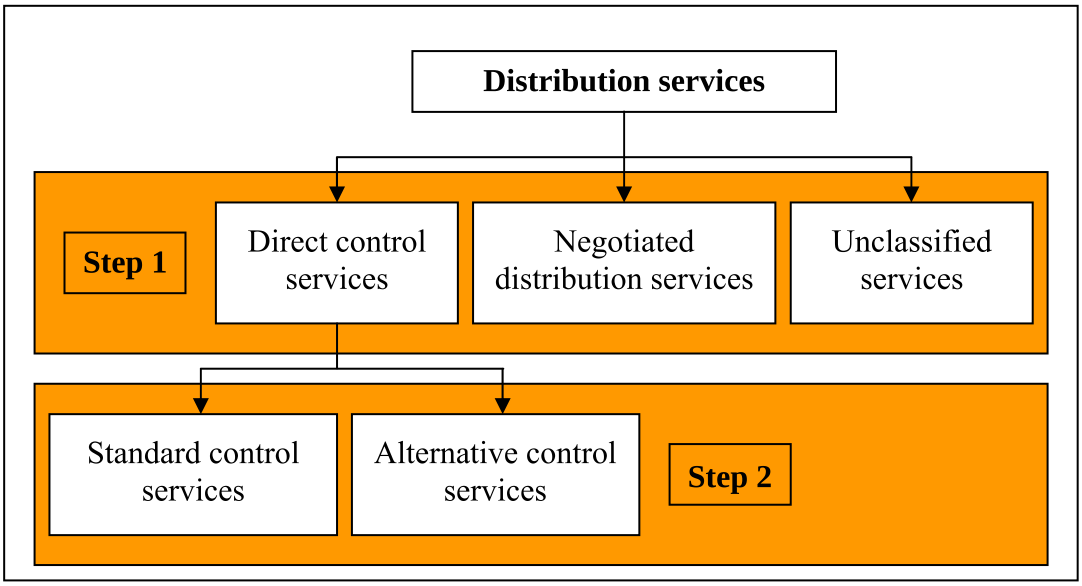
Distribution services can be grouped together for the purpose of classification, so that a single classification applies to each service in the group.[11]

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.[12] 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:

- there should be no departure from a previous classification (if the services have been previously classified under the NER), or
- (if there has been no classification under the NER) the classification should be consistent with the previously applicable regulatory approach,[13]

unless a different classification is clearly more appropriate. ETSA Utilities' current service classifications are listed in appendix A.

Figure 2.1 – Distribution service classification process



Source: NER[14]

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.[15]

[11] NER, cll. 6.2.1(b) and 6.2.2(b)
[12] NER, cll. 6.2.1(e) and 6.2.2(e)
[13] NER, cl. 6.2.1(d)
[14] NER, chapter 6, Part B.

Distribution services not classified as either of these are not regulated under the NER.[16]

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 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, electricity 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[17]
- 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

[15] NER, cl. 6.2.1(a)
[16] NER, cl. 6.2.1(a)
[17] NEL, s. 2F

- any other relevant factor.[18]

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.[19]

In classifying direct control services as 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)
- 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.[20]

2.3 AER's preliminary position on service classification

ETSA Utilities' distribution services are currently classified as either prescribed distribution services or excluded services. This classification occurred under the National Electricity Code, which has since been replaced by the NER.

Given the previous classification under the National Electricity Code, the AER must act on the basis that the classification should be consistent with the previously applicable regulatory approach, unless a different classification is clearly more appropriate.[21]

When regard is had to the regulatory approach to distribution services in the current (2005-10) regulatory control period, this gives rise to a presumption that, unless a different classification is clearly more appropriate:

[18] NER, cl. 6.2.1(c)
[19] NER, cl. 6.2.2(a)
[20] NER, cl. 6.2.2(c)
[21] NER, cll. 6.2.1(d) and 6.2.2(d)

- 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.

Having considered the requirements of the NER, the AER’s preliminary position was that no different classifications were clearly more appropriate, and that its likely approach would be to transition ETSA Utilities’ service classifications for the forthcoming regulatory control period in accordance with the presumption in the NER, as set out above.

The one exception to this was the pole and duct rental service. Pole and duct rental for non-electricity (e.g. telecommunications) purposes, which would typically involve broadband providers paying ETSA Utilities for access to install coaxial and fibre optic cables along the poles that comprise the distribution system, are instead regulated under the *Telecommunications Act 1997*. ETSA Utilities, as a holder of a carrier licence, is required to provide access to other carriers as requested, on terms and conditions governed by that Act. The AER’s preliminary position was that these services should therefore not be classified under cl. 6.2.1. As previously noted, if the AER decides against classifying a service, it is not regulated under the NER.

The AER’s preliminary position on ETSA Utilities’ service classifications for the forthcoming regulatory control period is set out in tables 2.1 and 2.2 below.

Table 2.1 – AER's preliminary position – classification of ETSA Utilities' direct control and negotiated distribution services

Service category	Direct control services	Negotiated distribution services
Network services	Network services at mandated standard	Network services at higher (or lower) than mandated standard
Connection services	Connection services at mandated standard New or upgraded connection services (to the extent the user is not required to make a financial contribution under the *Electricity Distribution Code*)	Connection services at higher (or lower) than mandated standard New or upgraded connection services (to the extent the user is required to make a financial contribution under the *Electricity Distribution Code*)
Metering services	Small customer standard meter provision and energy data services excluding special meter reads (type 6 metering installations) Unmetered metering services (type 7 metering installations) Two 'exceptional cases' of large customer metering services (type 1-4 metering installations) for legacy reasons	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 (type 1-4 metering installations)
Public lighting services	Nil	Provision of assets, operation and maintenance Operation and maintenance 'Energy only' service
Other services	Nil	All services currently listed in ETSA Utilities *Excluded Services Schedule* (not already covered in the previous categories), including: Provision of stand-by or temporary supply Asset relocations Disconnections and reconnections Recoverable asset repairs High load escorts Feeder standby service

Source: AER[22]

[22] AER, *Preliminary positions – Framework and approach paper – ETSA Utilities 2010-15*, June 2008, p.44.

Table 2.2 – AER's preliminary position – classification of ETSA 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[23]

2.4 Summary of submissions

The AER received three submissions in response to its preliminary position on service classification. Submissions were received from:

- ETSA Utilities
- Metropolis Metering Assets (Metropolis) and Centurion Metering Technologies (Centurion) (in a joint submission), and
- Origin Energy Retail (Origin).

ETSA Utilities generally accepts the preliminary position that the current classification of services is consistent with the requirements of the NER, and that "no different classification is clearly more appropriate" such as to warrant a departure from a previous classification.[24]

ETSA Utilities does, however, make additional qualifying comments in relation to one of the public lighting services and the Retailer of Last Resort (ROLR) services:

- ETSA Utilities considers that competition in the customer lighting equipment rate (CLER) public lighting service market may be sufficient to warrant declassification, that is, removal from regulation, and
- ETSA Utilities notes the uncertainty regarding its future obligation to provide ROLR services, and submits that the AER should include in its framework and approach paper its likely approach to classification of ROLR services, should ETSA Utilities remain the ROLR in the 2010-15 regulatory control period.

[23] AER, *Preliminary positions – Framework and approach paper – ETSA Utilities 2010-15*, June 2008, p.45.

[24] ETSA Utilities, Submission to AER's preliminary positions – Framework and approach paper – ETSA Utilities 2010-15, August 2008, p 6

ETSA Utilities also notes that the AER has not explicitly considered or listed all the services currently classified as excluded services in ETSA Utilities' current determination in its preliminary positions paper. ETSA Utilities recommends that the AER incorporate a complete list of negotiated distribution services (currently excluded services) in its final framework and approach paper to avoid any ambiguity.[25]

The submissions from Metropolis/Centurion and Origin comment only on the classification of metering services. Metropolis/Centurion and Origin argue that small customer standard metering services charges should be 'unbundled' from the DUOS charges, because small customers opting for a non-ETSA Utilities meter (a meter meeting the requirements of a type 1-4 meter) continue to pay ETSA Utilities' metering charges through the DUOS tariff even after the standard ETSA Utilities meter is no longer being used. This means that these customers are paying for their metering twice, which forms a barrier to entry into the metering provision market. These submissions are elaborated on in more detail in section 2.5.3.3 below.

2.5 Issues and AER's considerations

2.5.1 Distribution services

The NER defines a distribution service as 'a service provided by means of, or in connection with, a *distribution system*'.[26]

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

For the purposes of the framework for economic regulation of distribution services in chapter 6 of the NER, distribution services are taken to include network services, connection services, metering services, public lighting services and certain other services.

2.5.2 Considerations relevant to steps 1 and 2

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

At both steps of classification, if the NER require a service of a specified kind to be classified as a direct control or negotiated distribution service, or as a standard or alternative control service (as the case may be) then that service is to be classified in

[25] ETSA Utilities, *Submission to AER's preliminary positions – Framework and approach paper – ETSA Utilities 2010-15*, August 2008, p 7

[26] NER, chapter 10.

accordance with that requirement.[27] This requirement overrides all other considerations in chapter 6 of the NER. The NER do not require a distribution service provided by ETSA Utilities to be classified in a particular way pursuant to these clauses.

2.5.2.2 Presumption in favour of prior classification or classification consistent with the previously applicable regulatory approach

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.[28] 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, for the next regulatory control period:

- ETSA Utilities' prescribed distribution services should be classified as direct control services, and further classified as standard control services, and

- ETSA Utilities' excluded services should be classified as negotiated distribution services,

unless a different classification is clearly more appropriate.

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 and incorporate a CPI-X framework (or variant thereof) where the X-factor is determined according to a building block approach, and where individual tariffs are subject to the annual approval of the regulator.

The form of regulation applicable to ETSA Utilities' excluded services is closer to that of negotiated distribution services than 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.[29]

Under the NER, the AER must make a decision to classify a service as a direct control or negotiated distribution service, or as a standard control or alternative control

[27] NER, cll. 6.2.1(e) and 6.2.2(e).

[28] NER, cll. 6.2.1(d)(1) and 6.2.1(d)(2).

[29] Application of the presumption in favour of the previously applicable regulatory approach is likely to lead to a presumption in favour of prescribed distribution services being classified as direct control (standard control) services in each jurisdiction. However, whether or not the presumption would lead to excluded services being classified as direct control (alternative control) services or negotiated distribution services may differ from jurisdiction to jurisdiction depending on the particular form of regulation applied to excluded services in that jurisdiction.

service. The ‘default’ approach adopted by ESCOSA, which would equate to classifying all distribution services as direct (standard) control services, except for those specifically identified as negotiated distribution services, is not available under the NER. Nor is the flexibility which allowed ESCOSA to change the classification of a distribution service during the regulatory control period.

Direct control and negotiated distribution services must be separately listed, as must standard control and alternative control services. In the absence of ‘default’ classifications, it is necessary 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 control period, are classified.

This balance can be achieved by grouping services for the purpose of classification as provided for by the NER.[30] This approach to service classification has the advantage of classifying a class of activities, rather than the specific activities, allowing the specific definition or scope of services to change whilst maintaining the desired classification. Such broad classifications can be combined with a list of specific services that are included (but not limited to) that classification grouping.

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

2.5.3.1 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’.[31] Network services predominantly relate to services provided over the shared network used to service all network users connected to it. The term ‘network services’ encompasses much of a DNSP’s distribution services.[32]

[30] NER, cll. 6.2.1(b) and 6.2.2(b).
[31] NER, Chapter 10.
[32] Network 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.

AER’s preliminary position

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

On this basis, the AER’s preliminary position was that ‘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 (where permissible), 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.

Issues and AER’s considerations

No submissions were received on the classification of network services.

ETSA Utilities is likely to possess significant market power in the provision of ‘standard’ network services:

- Significant barriers to entry exist for the provision of ‘standard’ network services, limiting the potential for these services to be competitively supplied by providers other than ETSA Utilities.

- The principal barrier to entry is the significant capital costs of entry (which is a sunk cost) and consequent economies of scale and scope available to ETSA Utilities as the incumbent, which renders duplication of ETSA Utilities’ shared network by an alternative service provider 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 the shared network by an alternative provider is also likely to be technically unfeasible.

- There are strong network externalities (or interdependencies) between network services, and between network services and other distribution services, which generate operational and economic efficiencies through the operation of the meshed network as an integrated system. Moreover, competitive service providers are likely to face further barriers due to difficulty in establishing property rights to the network.

- There are limited viable substitutes for shared network services.

The AER's likely approach is therefore to classify these services as direct control services to be subjected to a direct form of price control.

Although ETSA Utilities has significant market power in the provision of 'standard' network services, 'non-standard' network services (e.g. services provided at higher than the mandated standard) are likely to be substitutable in that customers could substitute these services for 'standard' network services.[33] As ETSA Utilities may face a loss of revenue if customers shifted from 'non-standard' to 'standard' services, this may place some downward pressure on the extent to which ETSA Utilities can charge excessively high prices in its provision of 'non-standard' network services.

It is difficult to forecast the costs and magnitude of these 'non-standard' services, as by 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, rather than under a direct control framework where charges would need to be approved upfront (i.e. before a customer has specified its desired specifications and level of service). Whilst most of these 'non-standard' network services are likely to be non-contestable and/or non-competitive, it is noted that ETSA Utilities will be required to charge for negotiated distribution services 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.

AER's likely approach

The AER's likely approach is to classify ETSA Utilities' network services in a manner which is consistent with the previously applicable regulatory approach, as no other classification is clearly more appropriate.

Accordingly, 'standard' network services are likely to be classified as direct control services, and 'non-standard' services as negotiated distribution services. This means that all network services are likely to 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 (where permissible), than are required by the NER, the Electricity Distribution Code, or any other applicable regulatory instruments, or
- in excess of levels of service or plant ratings required to be provided by ETSA Utilities' assets,

which are likely to be classified as negotiated distribution services.

Network augmentations or extensions associated with new and upgraded connection points are addressed under the *Electricity Distribution Code*, together with the related connection services.[34] The AER's likely approach to network services associated with new or upgraded connection points is set out in the following section (connection services).

[33] NER, cl 6.2.1(c)(1)

[34] *Electricity Distribution Code* EDC/06, 1 January 2003 (as last varied in December 2006), Chapter 3.

2.5.3.2 Connection services

The NER defines connection services as 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.[35]

AER's preliminary position

The preliminary position was 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, the preliminary position was that 'standard' connection services should be classified as direct control services, and 'non-standard' services should be classified as negotiated 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 (where permissible), 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, the preliminary position was that connection services (and network services) associated with new or upgraded connection points:

- should be classified as negotiated distribution services to the extent the user is required to make a financial contribution under the *Electricity Distribution Code*, and
- should be classified as direct control services to the extent the user is not required to make a financial contribution under the *Electricity Distribution Code*.

Issues and AER's considerations

No submissions on the classification of connection services were received.

ETSA Utilities is likely to possess significant market power in the provision of 'standard' connection services. This market power arises from:

- Considerable network externalities achievable by ETSA Utilities owning the shared network (and providing network services), and providing 'standard' connection services which will connect a user to that shared network. Similarly, there are realisable network externalities between providing connection services and commissioning metering services, particularly in the case of small customer

[35] NER, Chapter 10

connections which are likely to require a type 5-7 metering installation (which ETSA Utilities exclusively provides). These interdependencies provide ETSA Utilities the advantage of achieving economies of scope and other operational and economic efficiencies.

- The energisation or electrical connection of a service connection can only be performed by ETSA Utilities as there are technical barriers which preclude non-distributor parties from providing that element of the service.

The AER's likely approach is therefore to classify these services as direct control services to be subjected to a direct form of price control.

'Non-standard' connection services are likely to be substitutable in that customers could substitute these services for 'standard' connection services.[36] It is difficult to forecast the costs and magnitude of these services, as these 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. The AER is therefore likely to classify 'standard' connection services as direct control services and 'non-standard' connection services as negotiated distribution services.

The current classification of connection services (and network 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*.[37]

The provisions regulating the amount customers contribute directly to new or upgraded connection points is set out in chapter 3 of the *Electricity Distribution Code*. A derogation in the NER preserves these arrangements relating to capital contributions for South Australia into the future.[38]

The *Electricity Distribution Code* sets a cap on the amount ETSA Utilities can directly charge a customer for a new or upgraded connection point and the associated extension or augmentation of the distribution network.[39] 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)

[36] NER, cl. 6.2.1(c)(1)
[37] ESCOSA, *2005-2010 electricity distribution price determination – part B – price determination*, April 2005, p.35. Italicised terms are as defined in the EDPD.
[38] NER, cl. 9.29.6.
[39] ESCOSA, *Electricity Distribution Code*, version 6, December 2006, p.A-32.

- *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'.[40]

The distributor's rebate is an amount that offsets the cost of the new or upgraded connection point. Where the rebate is greater than or equal to the sum of the other amounts, the customer is not required to contribute directly to this cost. For residential customers the distributor's rebate equals $3000. For non-residential customers the distributor's rebate equals whichever is the greater of $3000 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 countervailing power.[41] The information ETSA Utilities is required to provide the customer under the *Electricity Distribution Code* also reduces the barriers to entry for these services.[42]

The AER has no evidence to suggest the current classification and form of regulation are not effective. The AER is likely to classify connection services (and network services) associated with new or upgraded connection points as negotiated distribution services (to the extent a customer is required to make a financial contribution under the *Electricity Distribution Code*), acknowledging that 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 likely approach

The AER's likely approach is to classify ETSA Utilities' connection services in a manner consistent with the previously applicable regulatory approach, as no other classification is clearly more appropriate.

On this basis, 'standard' connection services are likely to be classified as direct control services, and 'non-standard' services 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 (where permissible), 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.

[40] ESCOSA, *Electricity Distribution Code*, version 6, December 2006, p.A-32.
[41] NER, cl. 6.2.1(c)(1).
[42] NER, cl. 6.2.1(c)(1).

In addition, connection services (or network services) associated with new or upgraded connection points:

- should be classified as negotiated distribution services – to the extent a user is required to make a financial contribution under the *Electricity Distribution Code*, and

- should be classified as direct control services – to the extent a user is not required to make a financial contribution under the *Electricity Distribution Code*.

2.5.3.3 Metering services

Each connection point in the NEM must have a metering installation.[43] 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 – the collation, processing, storage and provision of access to energy data.[44]

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.[45] The type structure generally refers to the quantity of electricity flowing through the connection point, for which different meter requirements are applied to different meter types (such as degree of accuracy in measuring consumption).

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[43] NER, cl. 7.3.1A(a).

[44] Chapter 10 of the NER defines 'energy data services' as the services that involve:

- collation of energy data from the meter or meter / meter association 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.

[45] Tier structure refers to whether or not the end-use customer purchases its electricity in its entirety from the local retailer. 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. The two different tiers of connection points are:

- 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.

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 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[46]

Type 4 applies to metering installations with flows less than 0.75 GWh, except where these metering installations are otherwise a type 5 or type 6 metering installation. Type 5 and 6 metering installations have a maximum consumption range of between 0 and 0.75GWh 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 except Queensland, where the range is between 0 and 100 MWh.[47]

Type 7 applies to connection points where no meter exists.

AER's preliminary position

The preliminary position was 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.

Different service classifications were 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. Service classification distinctions should be isolated to the type structure of metering installations, and the related characteristics of whether the customer is small (annual consumption less than 160MWh) or large, and whether the service is 'standard' or 'non-standard'. This was consistent with the previously applicable regulatory approach.

46 AEMC, *Rule determination – national electricity amendment integration of NEM metrology requirements rule 2008*, 6 March 2008, pp.7-8.

47 AEMC, Rule determination – national electricity amendment integration of NEM metrology requirements rule 2008, 6 March 2008, p.8.

The preliminary position was to:

- classify 'standard' small customer metering services (type 6 metering installations) as direct control services
- classify 'non-standard' small customer metering services (meters meeting the requirements of type 1-4 metering installations provided to small customers, and type 5 metering installations) as negotiated distribution services
- classify all large customer metering services (type 1-4 metering services provided to large customers) as negotiated distribution services, and
- classify the two 'exceptional cases' of type 1-4 meter provision services as direct control services for legacy reasons. These exceptional cases related to:
    - customers consuming between 160 and 750 MWh per annum who have types 1-4 metering installations provided prior to 1 July 2000
    - customers consuming more than 750 MWh per annum who have types 1-4 metering installations provided prior to 1 July 2005.
- classify unmetered metering services (type 7 metering installations) as direct control services

Summary of submissions

Submissions were received from Origin and Metropolis/Centurion[48] on the classification of metering services. ETSA Utilities supported the preliminary positions paper.

Origin and Metropolis/Centurion argue that all categories of metering service charges should be unbundled from ETSA Utilities' DUOS tariffs because small customers choosing an alternative to ETSA Utilities' basic type 6 meter, such as smart meters, are paying for their metering twice. They continue to pay metering charges to ETSA Utilities through the smeared cost of basic meter provision in the DUOS tariff, and they are also paying charges for the alternative meter to the alternative meter provider.[49] Origin and Metropolis/Centurion submit that this is a barrier to choice of meter providers (and meter data providers).

Origin and Metropolis/Centurion state that their involvement in the Federal Government's Solar Cities Program[50] to install smart meters has been significantly reduced, because the current bundling of metering service charges with ETSA Utilities' DUOS tariffs has increased the cost of smart meter deployment.

[48] Metropolis is a registered metering provider and Centurion is a registered meter data agent
[49] Metropolis Metering Assets Pty Ltd and Centurion Metering Technologies Pty Ltd Submission dated 22 August 2008 p. 2.
[50] As part of Federal Government's Solar Cities Program, Origin is a member of the Solar Cities consortium for a South Australian pilot project. This project includes the largest roll-out (at present) of smart meters in Australia. Metropolis/Centurion have been engaged by Origin Energy to install type 4 meters or 'smart meters' for 7000 homes and businesses in South Australia.

Both Origin and Metropolis/Centurion argue that it is appropriate to define charges separately for meter provision and metering data services. Metropolis/Centurion argue that separating these charges appropriately reflects the two forms of metering accreditation defined under the NER.

Issues and AER's considerations

ETSA Utilities' market power differs in relation to the large customer and small customer[51] metering (meter provision and energy data services) markets. The large and small customer metering service markets are discussed separately below.

Large customer metering service market

The provision of metering services to large customers is contestable, and this limits ETSA Utilities' market power in the provision of these services.

The NER provides that the person responsible for the provision, installation and maintenance of a metering installation for all customers (including first tier and second tier customers) is referred to as the responsible person.[52] For type 1-4 metering installations, a market participant may elect to be the responsible person.[53] Alternatively, a market participant may request ETSA Utilities (as the local network service provider or 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.[54]

These provisions of the NER provide that the provision, installation and maintenance for type 1-4 metering installations are contestable, in that a market participant (likely to be the retailer) can choose whether it elects to be, or requires ETSA Utilities to be the responsible person for these metering installations. This contestability applies to all customers regardless of their consumption (i.e. both large and small customers).

A market participant offering type 1-4 meter provision services can engage a metering provider other than ETSA Utilities, or choose to be the metering provider itself. This may provide the market participant with some countervailing power, as ETSA Utilities faces a loss of revenue should a market participant choose an alternative provider.[55] The presence of alternative type 1-4 metering providers (such as Metropolis) in the large customer market indicates that there are substitutes to the provision of type 1-4 meters by ETSA Utilities. There are currently around 20 metering providers registered with NEMMCO across the NEM, and in South Australia ETSA Utilities does not provide the majority of type 1-4 metering services. This may indicate that there is a reasonable level of competition in the large customer metering services market in South Australia.

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[51] Section 4 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)* defines a small customers as one whose annual electricity consumption level for a connection point is less than 160 MWh.

[52] NER, cl. 7.2.1.

[53] NER, cl 7.2.2(a).

[54] NER, cl. 7.2.3.

[55] NER, cll. 7.4.1-7.4.2.

The AER is therefore likely to classify all large customer metering (type 1-4 meter provision and energy data) services as negotiated distribution services, apart from the 'exceptional cases' noted above.

The costs associated with these 'exceptional cases' have 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. Accordingly departure from a direct control classification (consistent with the previous regulatory approach) is not clearly more appropriate. However to ensure that small customers (both those with and without an ETSA Utilities meter) are not partially paying for these metering services to large customers, it is appropriate that charges for these large customer metering services are unbundled from the DUOS charges. This is in line with the principle raised in the submissions from Origin and Metropolis/Centurion. This unbundling can be achieved through a direct control (alternative control) classification and is further discussed in section 6.5.2.

Small customer metering service market

ETSA Utilities' market power in the small customer metering market depends largely on the contestability of meter installations under the NER.

As the LNSP, ETSA Utilities is the responsible person for type 5-7 metering installations in South Australia and must, at its own initiative or at the request of a market participant[56], 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.[57]

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 ETSA Utilities. This regulatory barrier to entry is highly likely to provide ETSA Utilities with a significant degree of market power in the provision of meter installation services for type 5-7 meters.

ETSA Utilities' exclusivity over type 6 (basic accumulation) meter provision services prevents alternative providers from supplying these meters, and consequently there are no substitutes to ETSA Utilities services, other than small customers opting for a more expensive 'non-standard' meter. Similarly there are no substitutes to type 7 metering services (other than the installation of an actual meter). The AER is therefore likely to classify type 6-7 metering services as direct control services.

Under the NER type 5 metering provision services are non-contestable. However as these services are of a 'non-standard' nature, and provision of type 5 metering services to small customers by ETSA Utilities may to some degree compete with the provision of type 4 metering services from alternative providers, the AER does not consider that a direct form of price control is warranted. ETSA Utilities' provision of meters to small customers meeting the requirements of type 4 metering installations

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[56] 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.
[57] NER, cl. 7.2.3.

would also compete with the provision of these services from alternative providers. Accordingly, the AER is likely to classify these services in a manner consistent with the previously applicable regulatory approach and classify small customer 'non-standard' metering services as negotiated distribution services.

As noted above, Origin and Metropolis/Centurion argue that the 'bundling' of the type 6 metering services charges with DUOS charges creates a barrier to entry for alternative metering providers into the small customer metering market. This barrier occurs as small customers opting for a meter from an alternative provider, continue to pay ETSA Utilities for the provision of type 6 metering services (even though they are no longer receiving these services), and so effectively pay for their metering twice. The AER agrees that the unbundling of these charges should occur, and notes that this could be achieved by classifying type 6 metering services as negotiated distribution services. However, considering the market power that ETSA Utilities has in type 6 metering provision services (discussed above), this would not be appropriate. The AER considers that this unbundling can be best achieved through a direct control (alternative control) service classification. Classification as a direct (alternative) control service ensures that the charges for these services are unbundled from the charges for direct (standard) control services. The reasons for this approach are discussed below in section 2.5.4.

AER's likely approach

The AER's likely approach is to:

- classify 'standard' small customer metering services (type 6 metering installations) as direct control services
- classify 'non-standard' small customer metering services (meters meeting the requirements of type 1-4 metering installations provided to small customers, and type 5 metering installations) as negotiated distribution services
- classify all large customer metering services (type 1-4 metering services provided to large customers) as negotiated distribution services, and
- classify the two 'exceptional cases' of type 1-4 meter provision services as direct control services for legacy reasons. These exceptional cases relate to:
    - customers consuming between 160 and 750 MWh per annum who have types 1-4 metering installations provided prior to 1 July 2000
    - customers consuming more than 750 MWH per annum who have types 1-4 metering installations provided prior to 1 July 2005
- classify unmetered metering services (type 7 metering installations) as direct control services.

The issues raised in submissions from Origin and Metropolis/Centurion are considered further in section 2.5.4 below.

2.5.3.4 Public lighting services

Public lighting services currently provided by ETSA Utilities include:

- the provision of public lighting assets, along with the operation and maintenance of those assets – ETSA Utilities retains ownership of the assets. In South Australia these services are referred to as ‘street lighting use of system’ (SLUOS) services
- the replacement of failed lamps in customer owned streetlights – customers (road authority, local councils) retain ownership of the assets and are responsible for all other maintenance. In South Australia these services are referred to as ‘customer lighting equipment rate’ (CLER) services, and
- maintenance of a database relating to street lights, and recording and informing customers of streetlight faults reported to ETSA Utilities – customers retain ownership of the assets and are responsible for all maintenance (including replacement of failed lamps). In South Australia these services are referred to as ‘energy only’ services.[58]

The charges associated with these services relate only to the provision of public lighting services, and not to charges associated with the shared network. For example, in addition to paying for public lighting services, a local council would also pay for network services (for the conveyance of electricity through the distribution network up to the point of connection of the public lighting asset).

AER’s preliminary position

The AER’s preliminary position was to classify all public lighting services (SLUOS, CLER, energy only) as negotiated distribution services, which was consistent with the previous regulatory approach.[59]

Issues and AER considerations

ETSA Utilities was the only stakeholder to comment on the classification of public lighting services in the preliminary positions paper. Its comments on public lighting services were limited to the CLER public lighting services.

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[58] ESCOSA, *2005-2010 electricity distribution price determination – part A – statement of reasons*, April 2005, p.25.

[59] 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. 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
- 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). Whilst the form of control for SLUOS services differs somewhat from that applied to other excluded services, the AER considers the presumption in favour of a classification consistent with the previously applicable regulatory approach would still lead to a negotiated distribution services classification for 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 $14 million from SLUOS and CLER services. This amount is typical of the revenue ETSA Utilities earns each year from these services.

Street lighting services are contestable in that customers (local councils, Transport SA) do not have to ask ETSA Utilities to provide, operate and maintain their street lighting assets (i.e. customers do not have to opt for SLUOS services). Customers have the option of providing (and owning), operating and maintaining their own lights, and effectively avoiding all of ETSA Utilities' physical public lighting services (by using an 'energy only' service), or only employing ETSA Utilities to replace failed light bulbs in their lights (by using the CLER service). To some extent these options may provide some countervailing power to customers which may place some competitive constraint on ETSA Utilities' pricing of SLUOS services. However, the vast majority of public lighting in South Australia is still provided by ETSA Utilities through SLUOS services, which may indicate that most customers do not see providing their own public lighting assets (and only seeking the CLER or energy only services from ETSA Utilities) as commercially viable alternatives.

In the last determination ESCOSA concluded:

> 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.[60]

In its preliminary positions paper, the AER considered the representations made by the LGA and Transport South Australia in determining that it was likely to classify SLUOS services as negotiated services, as this was consistent with the previous regulatory approach and the preference of customers in the last determination. Neither Transport SA nor the LGA have indicated to the AER that this approach would no longer be appropriate.

ESCOSA is currently considering a claim, submitted by several councils and the Minister for Transport, on the fairness and reasonableness of SLUOS charges. The outcome from this process is not yet known. Depending on the timeframe of this process, the AER will consider the outcomes from the current claim during the determination process in determining whether the current form of regulation has been effective, and whether maintaining a classification similar to the current classification is appropriate.

ETSA Utilities notes the current classification of the CLER lighting service as an excluded service, which by operation of the presumption discussed in section 2.5.2.2

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

above would be classified as a negotiated distribution service. However, ETSA Utilities argues that due to the absence of barriers to competition CLER should be unclassified, and therefore unregulated. ETSA Utilities concedes that this approach may not be clearly more appropriate than classification of these services as negotiated distribution services, and submits that, if not resolved in distribution determinations for the forthcoming regulatory control periods in Queensland and South Australia, this issue should be considered in its 2015 distribution determination.

The AER has not been presented with any evidence to suggest that the barriers to entry for the provision of CLER services are so low as to warrant declassification (i.e. removal of all regulation). The AER has indicated in its framework and approach papers for Energex and Ergon Energy that it is likely to classify a similar service as a direct control (alternative control) service in Queensland.

AER's likely approach

The AER's likely approach is to classify ETSA Utilities' public lighting services in a manner consistent with the previously applicable regulatory approach, as no other classification is clearly more appropriate. This leads to all public lighting services (SLUOS, CLER, energy only) being classified as negotiated distribution services.

2.5.3.5 Other distribution services

The services already discussed in this chapter constitute the majority of ETSA Utilities' revenue from distribution services. However ETSA Utilities also provides other distribution services, of varying significance in terms of revenue and customer numbers, which are listed in the *Excluded Services Schedule* to its current determination.

ESCOSA defined excluded services as:

> … 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.[61]

ESCOSA's current *Excluded Services Schedule* is reproduced in full in Appendix A.

Most significant services in the *Excluded Services Schedule* are analysed in other sections of this paper. These include public lighting (section 2.5.3.4), new and upgraded connection points (section 2.5.3.2), service standards for network and connection services (sections 2.5.3.1 and 2.5.3.2 respectively), and retailer of last resort services (section 2.5.5). This section deals with the remaining services in the *Excluded Services Schedule*. These services include stand-by and temporary supply, services related to embedded generation, and pole and duct rental.

AER's preliminary position

The preliminary position was that, with the exception of pole and duct rental (for non-electricity purposes), which does not fall within the definition of a distribution service under the NER, ETSA Utilities' 'other' distribution services, currently listed in its

[61] ESCOSA, *2005-2010 Electricity Distribution Price Determination – part A – statement of reasons, April 2005*, p 26.

Excluded Services Schedule, should be classified in a manner which is consistent with the previously applicable regulatory approach, as no other classification was clearly more appropriate. On that basis, the AER stated that these services were likely to be classified as negotiated distribution services.

Issues and AER's considerations

ETSA Utilities noted that the AER had not explicitly listed all the services currently classified as excluded services (and listed in ETSA Utilities' *Excluded Services Schedule*) in its preliminary positions paper, and recommends that a complete list of negotiated distribution services (currently excluded services) be incorporated in its final framework and approach paper to avoid any ambiguity.[62] There is merit in avoiding any such ambiguity, and a full listing of all services that the AER is likely to classify as negotiated distribution services has been included in Appendix B.

These other services are commonly ancillary or related to a 'core' service such as a network, connection or metering services. For instance, the moving of mains, services or meters, and providing temporary disconnection or line insulation to accommodate developments of end-users' premises are ancillary services to network and connection services. Similarly, network augmentation to accommodate an embedded generator is ancillary to network services. Network externalities are likely to produce economies of scope and operational efficiencies that may form barriers to entry.

Investigation and testing services include the investigation and testing of meters. ETSA Utilities is likely to possess some market power in relation to investigating and testing type 5-7 metering installations as it has exclusivity over those metering installations under the NER.[63]

There are clear network externalities between the provision of the 'core' services and the provision of these other ancillary services. These network externalities are likely to heighten any barriers to entry and therefore reinforce ETSA Utilities' market power. It would be expected that ETSA Utilities, having considerable market power in the provision of these core services, could leverage that market power into the other services markets.

Conversely, the elasticity of demand for, and the substitutable nature of, some of these other services may also be greater than for core distribution services, providing customers with some countervailing market power.[64] The less significant nature of many of these services may warrant a less intrusive regulatory approach than for the core distribution services. These factors combined with the presumption that the classification should be consistent with the previously applicable regulatory approach, lead the AER to conclude that a classification other than a negotiated distribution services classification is not clearly more appropriate, with the following exception.

As indicated in the preliminary positions paper, pole and duct rental for non-electricity purposes, such as telecommunications purposes, are regulated under another regulatory framework. Holders of Carrier Licences, such as ETSA Utilities,

[62] ETSA Utilities, *Submission to AER's Preliminary positions Framework and approach paper, ETSA Utilities 2010-15*, August 2008, p 7.
[63] NER, cl 7.2.3.
[64] NER, cl. 6.2.1(c)(1).

are required under the *Telecommunications Act 1997* to provide access to other carriers if requested.[65] The terms and conditions of access are governed by the *Telecommunications Act 1997*. The AER therefore considers it clearly more appropriate not to classify these services under cl. 6.2.1. As previously noted, if the AER decides against classifying a service, it is not regulated under the NER.

AER's likely approach

The AER's likely approach, with the exception of pole and duct rental (for non-electricity related purposes), is to classify ETSA Utilities' 'other' distribution services as negotiated distribution services, which is consistent with the previously applicable regulatory approach. A full list of these services is provided in Appendix B.

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

The NER divides direct control services into standard and alternative control services. As stated, the presumption under the NER is that ETSA Utilities' prescribed distribution services will become standard control services. This section analyses whether a classification as an alternative control service is clearly more appropriate for any of these services.

2.5.4.1 AER's preliminary position

The preliminary position was that all of ETSA Utilities' prescribed distribution services should be classified as direct control services, and further classified as standard control services, as a different classification was not clearly more appropriate.

2.5.4.2 Issues and AER's considerations

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

> the potential for development of competition in the relevant market and how the classification might influence that potential[66]

is similar to the form of regulation factors the AER must have regard to in the first stage of classification. Both involve a market power assessment, however the meaning of this factor is arguably broader in scope.

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

> - 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.[67]

[65] *Telecommunications Act* 1997, Sc. 1, cl. 17(1).
[66] NER, cl. 6.2.2(c)(1).

Network services, connection services, public lighting services and ‘other’ services

For some network services, connection services, public lighting services and ‘other’ services provided by ETSA Utilities, the potential for development of competition may exist, and costs may be directly attributable to the customer to whom the service is provided. The AER has already indicated that it is likely to classify these services as negotiated distribution services (see section 2.5.3).[68]

When regard is had to administrative costs, the AER does not consider that the classification of any of the network and connection services identified as direct control services as alternative (instead of standard) control services is warranted in this instance.

Metering services

As discussed in section 2.5.3.3, the AER’s likely approach is to classify the following metering services as direct control services:

- ‘standard’ small customer metering services (type 6 metering installations) and unmetered services (type 7 metering installations), both for market power reasons, and
- the following two ‘exceptional cases’ of type 1-4 meter provision services for legacy reasons:
    - customers consuming between 160 and 750MWh per annum who have types 1-4 metering installations provided prior to 1 July 2000, and
    - customers consuming more than 750MWh per annum who have types 1-4 metering installations provided prior to 1 July 2005.

Type 1-4 metering installations are contestable for all customers (small and large customers) regardless of energy consumption. Small customers can opt for a type 1-4 meter (in practice a type 4 or ‘smart meter’) and thereby obtain an alternative meter as a substitute for a basic type 6 meter. Type 4 metering installations are to some extent a substitute for the basic type 6 meter, though type 4 meters have greater functionality.

Origin and Metropolis/Centurion argue that alternative metering providers face a barrier to entry into the small customer metering market. Under the current regulatory arrangements, small customers opting for a type 4 meter continue to pay for type 6 metering service charges because they are bundled with the DUOS tariff, even though the basic type 6 meter is no longer in use.

The AER considers this bundling to be a barrier to entry faced by alternative metering providers entering into the small customer market. Classifying type 6 metering

[67] 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’.

[68] NER, cl. 6.2.2(c)(1) and 6.2.2(c)(5).

services as direct (standard) control services, which would be consistent with the previous regulatory approach, would likely lead to the bundling of these charges being continued. The AER considers that it is more appropriate to adopt a classification that will remove this barrier, through unbundling metering services charges and only levying type 6 metering service charges on customers with those metering installations.

There is a possibility that not all type 6-7 metering related costs would be avoided by ETSA Utilities if it ceased to provide these services. Consequently, it may not be appropriate to unbundle all components of type 6-7 metering service charges.

The avoided components of type 6 metering service charges are likely to include all costs associated with meter provision services (the provision, installation, routine inspection and maintenance of metering installations) and at least the meter read component of energy data services. The AER's likely approach is to classify these 'variable' type 6 metering services as direct (alternative) control services.

Some costs associated with type 6 energy data services may be unavoidable (such as data storage). The AER's likely approach is to classify these 'fixed' type 6 metering services as direct (standard) control services.

Classification in this manner is appropriate having regard to the extent that the costs of providing the different aspects of 'standard' small customer metering services are, or are not, directly attributable to the customer to whom the service is provided.[69] Classification in this manner is also likely to promote the development of competition in the small customer metering market.[70]

In its regulatory proposal, the AER expects ETSA Utilities to allocate its standard small customer metering services costs into the components that ETSA Utilities considers are fixed and variable. The AER will assess the reasonableness of ETSA Utilities' cost allocation in making its distribution determination.

ETSA Utilities does not consider that the current bundling creates a significant barrier to entry as argued by Origin and Metropolis/Centurion. Whilst ETSA Utilities does not oppose unbundling in principle, it has suggested that the increased administrative costs of unbundling are likely to outweigh the benefits due to the low level of avoidable costs. The AER considers that the potential increased administrative costs arising from classification in this manner are unlikely to outweigh the potential benefits from the more cost reflective pricing that will result from these classifications and the consequent unbundling of the 'variable' standard small customers metering charges from DUOS charges.

However as the incremental costs involved in providing type 7 metering services are likely to be minimal (and relate only to energy data services), the AER does not consider there is a net benefit from unbundling charges for these services from the DUOS tariff. The AER is therefore likely to classify type 7 metering services as direct (standard) control services, consistent with the previously applicable regulatory approach.

[69] NER, cl. 6.2.2(c)(5)
[70] NER, cl. 6.2.2(c)(1)

As the costs of providing the ‘exceptional cases’ described above are also directly attributable to the large customers receiving the service, the charges relating to these services should similarly be unbundled from the DUOS tariffs. Accordingly a different classification to one that is consistent with the previous regulatory approach (which would be a direct control (standard control) classification is clearly more appropriate. The AER’s likely approach is to also classify these services as direct control (alternative control) services.

2.5.4.3 AER’s likely approach

The AER’s likely approach is to further classify all direct control services that relate to network or connection services as standard control services.

The AER’s likely approach is to further classify the direct control services that relate to metering services in the following manner:

- ‘variable’ standard small customer metering services (type 6 metering installations) as alternative control services
- ‘fixed’ standard small customer metering services (type 6 metering installations) as standard control services
- unmetered services (type 7 metering installations) as standard control services, and
- the following two exceptional cases of type 1-4 meter provision services as alternative control services:
    - customers consuming between 160 and 750MWh per annum who have types 1-4 metering installations provided prior to 1 July 2000, and
    - customers consuming more than 750MWh per annum who have types 1-4 metering installations provided prior to 1 July 2005.

2.5.5 Retailer of last resort services

ETSA Utilities is presently the retailer of last resort (ROLR) in South Australia. The current obligation expires on 30 June 2010, at the end of the current regulatory control period.[71]

2.5.5.1 AER’s preliminary position

Given the uncertainty around whether or not ETSA Utilities will retain its role as the South Australian ROLR in the forthcoming regulatory control period, the preliminary position was to defer consideration of the appropriate regulatory arrangements until ETSA Utilities future role became clear.[72]

[71] *Electricity Act (South Australia) 1996*, section 23(3)

[72] AER, *Preliminary positions – Framework and approach paper – ETSA Utilities 2010-15*, June 2008, p.42.

2.5.5.2 Issues and AER's considerations

ETSA Utilities submits that the issue of whether it will continue to be the ROLR may not be determined before the framework and approach paper is finalised, or by the time it has to submit its regulatory proposal to the AER. ETSA Utilities states that if it is the ROLR, it will require the following regulatory arrangements:

- a standard control service classification for ROLR establishment activities
- a negotiated distribution service classification for ROLR event activities (i.e the retailing of electricity to affected customers should an ROLR event actually occur), and
- a pass-through event for standard control services to cater for the difference between actual ROLR event costs and the costs recovered through the negotiated distribution services charges above.

The AER recognises ETSA Utilities' interest in obtaining certainty as to the treatment of the costs of providing ROLR services should its obligations continue for all or part of the forthcoming regulatory control period. However, while its responsibilities as the ROLR are imposed as a term of its electricity distribution licence, ROLR services do not fall within the definition of distribution services in the NER as services provided by means of, or in connection with, a distribution system.[73] By their nature these services therefore can not be classified under chapter 6.[74]

2.5.5.3 AER's likely approach

ROLR services do not fall within the definition of distribution services in the NER. The AER is therefore unable to classify these services under chapter 6 for the purposes of its distribution determination.

2.6 AER's likely approach to service classification

Having given full consideration to the relevant provisions of the NEL and the NER, the AER does not consider that departure from a classification consistent with the previously applicable regulatory approach for network services, connection services, public lighting services and 'other' distribution services is warranted. No other classification is clearly more appropriate at this time. The exception to this is pole and duct rental (for non-electricity purposes) service, currently classified as an excluded services and listed under 'other' services, which does not fall within the definition of distribution service under the NER, and consequently cannot be classified. For network services, connection services, public lighting services and 'other' services, the AER's likely approach is therefore:

- to classify ETSA Utilities' current prescribed distribution services as direct control services, and further classify as standard control services for the next regulatory control period, and

[73] A distribution system is defined in chapter 10 of the NER as a distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system.

[74] The AER notes that, in the current regulatory period, ESCOSA was able to include ROLR services in its EDPD under the *Electricity Act*.

- to classify ETSA Utilities’ current excluded services as negotiated distribution services for the next regulatory control period.

The AER does, however, consider it clearly more appropriate to depart from a classification that is consistent with the previous regulatory approach for certain metering services. The AER’s likely approach in this respect is to:

- classify ‘standard’ small customer metering services (type 6 metering installations) as direct control services, and further classify:
  - ‘fixed’ standard small customer metering services (type 6 metering installations) as standard control services, and
  - ‘variable’ standard small customer metering services (type 6 metering installations) as alternative control services
- classify two exceptional cases of type 1-4 meter provision services as direct control services, and further as alternative control services. These exceptional cases relate to:
  - customers consuming between 160 and 750 MWh per annum who have types 1-4 metering installations provided prior to 1 July 2000, and
  - customers consuming more than 750 MWh per annum who have types 1-4 metering installations provided prior to 1 July 2005.

A classification consistent with the previously applicable regulatory approach would have resulted in a direct (standard) control classification for each of the above metering services. An alternative control classification is clearly more appropriate to facilitate the ‘unbundling’ of these charges from DUOS charges, leading to a more cost reflective outcome. This is expected to facilitate competition in the small customer metering market. The AER considers the remaining metering services should be classified in a manner which is consistent with the previously applicable regulatory approach.

ROLR services do not fall within the definition of distribution services in the NER. The AER is therefore unable to classify these services under chapter 6 for the purposes of its distribution determination.

The AER’s likely approach to classification of distribution services provided by ETSA Utilities in the forthcoming regulatory period is set out in tables 2.4 and 2.5 below. A complete listing of all the services under each classification under the AER’s likely approach is contained in appendix B.

Table 2.4– AER's likely approach – 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 New or upgraded connection services (to the extent the user is not required to make a financial contribution under thee *Electricity Distribution Code*)	Connection services at higher (or lower) than mandated standard New or upgraded connection services (to the extent that the user is required to make a financial contribution under the *Electricity Distribution Code*)
Metering services	Small customer standard meter provision and energy data services (type 6 metering installations) Unmetered metering services (type 7 metering installations) Two 'exceptional cases' of large customer metering services (type 1-4 meter provision services), being: - customers consuming between 160 and 750 MWh per annum who have types 1-4 metering installations provided prior to 1 July 2000, and - customers consuming more than 750 MWH per annum who have types 1-4 metering installations provided prior to 1 July 2005.	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 (type 1-4 metering installations)
Public lighting services	Nil	Provision of assets, operation and maintenance Operation and maintenance 'Energy only' service
Other services	Nil	Remaining services listed in appendix B as negotiated distribution services, which includes: - Provision of stand-by or temporary supply - Asset relocations - Disconnections and reconnections - Electricity Distribution and Electricity Metering Codes - Embedded generation

Source: AER analysis

Table 2.5– AER's likely approach – ETSA 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	'Fixed' standard small customer metering services (type 6 metering installations) Unmetered metering services (type 7 metering installations)	'Variable' standard small customer metering services (type 6 metering installations) Two 'exceptional cases' of large customer metering services (type 1-4 meter provision services), being: - customers consuming between 160 and 750 MWh per annum who have types 1-4 metering installations provided prior to 1 July 2000 - customers consuming more than 750 MWH per annum who have types 1-4 metering installations provided prior to 1 July 2005.
Public lighting services	Nil	Nil
Other services	Nil	Nil

Source: AER analysis

3 Form of Control

3.1 Introduction

A distribution determination imposes controls on the prices of direct control services, the revenue to be derived from direct control services, or both.[75] This chapter states the form of control to be applied to ETSA Utilities' direct control services for the forthcoming regulatory control period.

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

The AER's likely approach to the classification of ETSA Utilities' distribution services as standard control, alternative control or negotiated distribution services was discussed in chapter two of this paper.

3.2 Requirements of the National Electricity Law and Rules

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.[76]

Unlike other elements of the framework and approach paper, the statement of the form of control in this framework and approach paper is binding on the AER and ETSA Utilities for the relevant distribution determination.[77]

3.2.1 Available control mechanisms

Control mechanisms in the NER comprise two parts:

- the form of control mechanism[78]
- the basis of the control mechanism.[79]

The forms of control mechanisms that may be applied to direct control services under the NER are:

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

[75] NER, cl. 6.2.5(a)
[76] NER, cl. 6.8.1(c)
[77] NER, cl. 6.12.1(11), (12)
[78] NER, cl. 6.2.5(b)
[79] NER, cl. 6.2.6(a)

- 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.[80]

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.

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 chapter 6, part C of the NER.[81]

The control mechanism for alternative control services must have a basis specified in the distribution determination.[82] This may, but need not, utilise elements of chapter 6, part C, and if it does, may do so with or without modification. For example, the control mechanism may (but need not) use a building block approach, and may (but need not) incorporate a pass-through mechanism.[83]

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.[84]

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.[85]

[80] NER, cl. 6.2.5(b)
[81] NER, cl. 6.2.6(a)
[82] NER, cl. 6.2.6(b)
[83] NER, cl. 6.2.6(c).
[84] NER, cl. 6.2.5(c)
[85] NER, cl. 6.2.5(d)(1)

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.[86] While most provisions relating to ETSA Utilities ceased on 30 June 2005 (at the end of ETSA Utilities' first regulatory control period), the EPO contains certain provisions that will continue to apply in the 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.[87]

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.

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 9 of the NER sets outs derogations from the application of chapter 6 that are specific to the distribution determination for ETSA Utilities for the regulatory control period commencing in 2010.

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[86] *National Electricity (South Australia) Act 1996*, s. 18(4)
[87] *National Electricity (South Australia) Act 1996*, s. 18(6).

In particular:

- The distribution determination must allow ETSA Utilities to carry forward impacts associated with the calculation of Maximum Average Distribution Revenue (MADR) under its 2005-10 price determination into the 2010/11 and 2011/12 regulatory years.[88]
- The following side constraint is to be applied to tariffs for small customers[89] 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.[90]

- 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.[91]

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

3.3 AER's preliminary position on form of control

The current control mechanism applied to ETSA Utilities' prescribed services is a variant of an average revenue cap (revenue yield). The basis of the control mechanism is a variant of CPI-X.

The preliminary position was that the form of control applied to prescribed services in the current regulatory control period satisfied the requirements of the NER, and could be applied to standard control services in the forthcoming regulatory control period subject to two adjustments:

1. Reducing the dependence of allowed revenue on out-turn electricity volumes (Qt)

The preliminary position was that if the current control mechanism were 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. As the existing adjustment mechanism has the potential to create undesirable outcomes such as price shocks and other risks to users of the distribution network, the AER considered that a Q-factor carryover mechanism should be introduced to ensure that weather related volume risks for consumers and ETSA Utilities are mitigated.

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

[89] 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).

[90] 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.

[91] NER, cl. 9.29.5(f)

2. Profit sharing of negotiated and unregulated services (Pt)

The preliminary position was that the NER do not allow the profit sharing mechanism (P-factor) applied in the 2005-10 EDPD to be included in the distribution determination for the next regulatory control period. P-factor adjustments from the 2005-10 regulatory period can, however, be accommodated through an EDPD carry-over mechanism of the nature contemplated in the preliminary positions paper to treat the impacts associated with the calculation of MADR referred to in the derogation.

In its preliminary positions paper, the AER did not propose to classify any distribution services provided by ETSA Utilities as alternative control services, and so did not address the form of control that would apply to any such services.

3.4 Summary of submissions

ETSA Utilities was the only stakeholder to make a submission on the AER's preliminary position on form of control mechanisms.

ETSA Utilities identifies a number of issues with its current form of control, and submits that a transition to a weighted average price cap (WAPC) or 'tariff basket' would be more appropriate.

As explained in chapter 2 of this paper, in response to submissions from Origin and Metropolis/Centurion regarding competition in small customer metering services, the AER has determined that it is likely to classify variable standard small customer metering services (type 6 metering installations) and certain exceptional type 1-4 metering services as alternative control services, to facilitate unbundling of metering charges. Given this likely approach, the AER has set out the form of control mechanism that will apply to these alternative control services in this chapter.

3.4.1 Transition to a weighted average price cap (WAPC) or 'tariff basket'

For its standard control services, ETSA Utilities proposes a movement from the current control mechanism to a WAPC or 'tariff basket'.[92] It submits that the decision to adopt the current form of control was made in response to factors that, while influential at the time, are no longer relevant to, or of lesser significance for, the 2010-15 period.[93] ETSA Utilities submits that a move to a WAPC would be more appropriate, and would provide a consistency across the NEM.

3.4.2 Issues with the current control

ETSA Utilities submits that under the current form of control the application of the NER side constraints and uncertainty in sales and demand growth would introduce a number of issues, which are discussed below.[94]

[92] ETSA Utilities, *Submission to AER's Preliminary positions – Framework and approach paper – ETSA Utilities 2010-15*, Submission in response, August 2008, p. 8.
[93] ibid., p. 9.
[94] ibid., p. 10.

3.4.2.1 NER side constraints

ETSA Utilities notes that the side constraint of CPI-X + 2 per cent that will apply under the NER in the 2010-15 regulatory control period is more restrictive than that which applied under the EDPD in the current period (CPI - X + 3.5 per cent),[95] and submits that this creates a high risk that weather variability will prevent it from recovering its maximum allowable revenue (MAR) when a high sales year is followed by a low sales year. It submits that under the current control mechanism, the flow on effects of such a scenario would create significant price volatility. Furthermore, to recover the allowable revenue in the short-run a price movement would need to occur that would be in breach of the NER side constraint. Whilst it acknowledges that with the introduction of the 'Q carry-over mechanism' the revenue shortfall would be recovered in the subsequent period, ETSA Utilities submits that it would experience short term cash-flow issues in the order of $20-$40 million.

ETSA Utilities also notes that any additional modification to what is already a variation on a revenue yield approach is a further deviation from standard forms of control, which it considers undesirable.[96]

3.4.2.2 Uncertainty in sales and demand growth

ETSA Utilities notes that the impacts of changes in economic growth and customer behaviour create uncertainty in sales and demand growth.

It submits that under the current control mechanism the combination of largely fixed revenues and unexpectedly high economic growth would result in a shortfall in cash flows, as the fixed revenues may be insufficient to fund additional capital and operating expenditures.[97] The flow on effects will result in price volatility as the additional capital expenditure is rolled into the asset base for the subsequent period. ETSA Utilities submits that a WAPC would provide a natural hedge to avoid this issue, and may result in smoother prices. On the other hand, it notes that in a low economic growth scenario it would be overcompensated for growth that failed to materialise.

ETSA Utilities submits that in the 2010-15 regulatory control period factors such as government policy, the media and rising prices from emissions trading could lead to changes in consumer behaviour and possible lower demand.[98] Such factors could include government policy to phase out electric hot water systems or increased media and public awareness on the effects of climate change. However, it submits that in extreme peak demand consumer behaviour is unlikely to be influenced. For example, ETSA Utilities suggests that when the weather is extremely hot the value of energy usage to consumers is high, and customers will turn on air conditioning units regardless of other issues such as effects of climate change. ETSA Utilities concedes that when these two factors are combined a WAPC may lead to a deficiency to address capital requirements for peak demand, and that its risks in such a situation would be best mitigated under a revenue cap or its current form of control.

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[95] ibid., p. 11.
[96] ibid., p. 11.
[97] ibid., p. 12.
[98] ibid., p. 13.

ETSA Utilities considers addressing the risks associated with a high growth scenario, to be of more primary importance than the risks associated with changes in consumer behaviour. It submits that the incentives and risks associated with a WAPC are materially more balanced than those available under the current form of control.[99]

3.4.3 Additional benefits of the WAPC

ETSA Utilities submits that a move to a WAPC would be more compliant with the NER than the current form of control.[100] It submits that a WAPC provides additional benefits in the form of:

- greater price-cost reflectivity
- a reduction in the AER's administrative costs
- a consistent form of control to that in New South Wales and Victoria, and
- a reduction in in-period and inter-period price volatility.

ETSA Utilities acknowledges AER's concerns that distribution price signals may not be passed on to consumers, but notes that it is more probable under the WAPC than the current form of control and also outside of ETSA Utilities' control.

3.4.4 Incentives and risks

ETSA Utilities recognises significant risks to both distributors and customers through errors in forecasting sales growth.[101] It notes the uncertainty in forecasts due to economic and population growth, emissions trading and energy efficiency policies, and the ability to mitigate such risks. It also acknowledges the view expressed in the AER's preliminary positions paper that each form of control mechanism may create different incentives for the distributor which may result in undesirable behaviour. ETSA Utilities recognises that there is no 'perfect' revenue control relating to incentives and risks, and that a form of control that provides the best compromise must be selected.

3.4.5 Disincentives to undertake demand management

ETSA Utilities concedes that a move to a WAPC would decrease the incentives to engage in demand management activities,[102] but submits that this consideration should be of secondary concern in selecting a form of control. ETSA Utilities proposes the implementation of an incentive mechanism such as a 'D-factor' to address this issue. The AER's likely approach to the application of a demand management incentive scheme to ETSA Utilities in the forthcoming regulatory control period is discussed in chapter 6 of this framework and approach paper.

3.4.6 Metering services

In response to the preliminary positions paper, Origin and Metropolis/Centurion propose that small customer metering service charges be unbundled from the

[99] ibid., p. 13.
[100] ibid., p. 14.
[101] ibid., p. 9.
[102] ibid., p. 13.

distribution use of system (DUOS) tariffs to facilitate competition in the meter provision market. As discussed in chapter two of this paper, these submissions suggest that the current bundling of metering services acts as a barrier to entry for service providers as the 'smeared' cost of basic metering costs provides little incentive for the retailer to seek out choice or to seek out improved metering technologies or solutions.[103] Under current arrangements small customers who utilise an alternative meter in effect pay for their metering twice.[104] It is submitted that, through the unbundling of metering service charges, customers can make better informed choices regarding their metering service provider which will enhance competition.[105]

3.5 Issues and AER's considerations – standard control services

In its framework and approach paper the AER must state the form of control mechanism or mechanisms that will apply to standard control services during the 2010-15 regulatory control period.

The factors to which the AER must have regard when deciding on the control mechanism to apply to standard control services are set out in section 3.2.2 above.

In response to the preliminary positions paper, ETSA Utilities' submission proposes a transition to a WAPC form of control for the 2010-15 regulatory control period.

A number of elements of the form of control proposed in the preliminary positions paper will apply regardless of the mechanism ultimately applied:

- the application of the service target performance incentive scheme within the form of control
- the application of the undergrounding allowance required by the EPO
- the removal of the profit sharing mechanism applied in the 2005-10 EDPD
- the application of an EDPD carryover mechanism to carry forward impacts associated with the calculation of Maximum Average Distribution Revenue (MADR) under ETSA Utilities' 2005-10 price determination into the 2010/11 and 2011/12 regulatory years, and
- the application of the constraint on the fixed supply charge component of the tariff for small customers.

ETSA Utilities' submission was silent on these matters. The AER is not aware of any reason to depart from its preliminary positions in these respects.

103 Origin Energy Retail Ltd, *Preliminary framework paper – ETSA Utilities 2010-15 Price Determination* Submission in response, September 2008, p.1.

104 Metropolis Metering Assets Pty Ltd and Centurion Metering Technologies Pty Ltd, *Consultation on ETSA Utilities Distribution Determination 2010-15 – Metering Services*, Submission in response, August 2008 p. 3.

105 ibid., p. 2.

The matters raised in ETSA Utilities' submission are considered below in the context of the NER requirements. In considering ETSA Utilities' submission, the AER has had regard to advice from the ACCC/AER's economic consultant Dr Darryl Biggar on the relative merits of the proposed transition to a WAPC. That advice is provided at appendix C to this framework and approach paper.

3.5.1 The regulatory arrangements applicable in the current regulatory period

Similar to the approach taken in service classification, the AER has considered the form of control mechanisms applied under the present or earlier legislation. Clauses 6.2.2(c)(3) and 6.2.2(c)(4) of the NER have been taken into account. As this is the first distribution determination for ETSA Utilities under the new chapter 6 framework, the AER only intends to depart from the current form of control where there is evidence that such a departure is appropriate.

3.5.2 The need for efficient tariff structures

ETSA Utilities' submission suggests that a WAPC is recognised by economists as the form of control which is most supportive of efficient tariff structures and provides the greatest incentive to price-cost reflectivity for DNSPs.[106]

Under certain assumptions it is possible that a WAPC will lead to efficient tariffs – that is, tariffs which recover the fixed costs as efficiently as possible while ensuring that prices, especially at the margin, reflect the structure of costs.[107]

Since the current structure of ETSA Utilities' tariffs is not reflective of its underlying costs, it may take some time for a transition to a more efficient tariff structure to occur. In addition, it is not clear at this stage to what extent the structure of distribution prices will be passed on by retailers to customers. If the distribution charges are averaged or 'smeared' across retail customers, a DNSP may not have incentives to set the distribution tariffs efficiently under a WAPC. The AER acknowledges ETSA Utilities' argument that, in the current regulatory period, distribution price signals have been passed on to customers. However, it is unclear whether it can be assumed this will continue going forward.

On balance, the AER considers that the WAPC form of control has the greater potential to lead to efficient, cost-reflective tariffs than the previous form of control, but this will need to be kept under review.

3.5.3 Administrative costs

There are no clear grounds for favouring the WAPC approach over the current form of control on the basis of administrative costs.[108] Under a WAPC there may be a simplifying of some administrative roles vis-à-vis ETSA Utilities' current form of control, as only information on historic sales is needed when verifying annual pricing changes. However, when setting the opening prices in each regulatory control period, the AER would still need to verify sales forecasts.[109] The AER recognises that the

[106] ETSA Utilities, *Submission in response*, op. cit., p 15.
[107] Biggar, *Report to the AER*, op. cit., p 9.
[108] ibid., p. 10.
[109] ibid., p. 10.

WAPC approach will do away with the administration of the under- and over-recovery mechanism in ETSA Utilities' current control mechanism.

3.5.4 The desirability of consistency

The AER does not consider that consistency in the form of control applied across jurisdictions should be determinative in selection of a form of control at this time.

As noted in the preliminary positions paper, currently there is no consistency across jurisdictions in the form of control applied. The application of a weighted average price cap, an average revenue cap and a revenue cap each occurs (subject to minor variations) in two jurisdictions.

ETSA Utilities notes in its submission that WAPC form of control mechanisms are currently applied to DNSPs in both New South Wales and Victoria (accounting for more than 60 per cent of the NEM by energy volume).[110] However, retention of that form of control in New South Wales is required for the 2009-14 regulatory control periods, by virtue of transitional arrangements in the NER. Further, a decision on the form(s) of control to be applied to Victorian DNSPs going forward will be made by the AER as part of the framework and approach process scheduled to commence by 1 January 2009, and will not be finalised until May 2009. It is therefore not certain that a transition to a WAPC in South Australia would result in greater consistency across jurisdictions.

3.5.5 Any other relevant factor

In addition to the matters set out above, in deciding on the form of control the NER require the AER to have regard to any other relevant factor.[111] In support of its recommendation, ETSA Utilities' submission raised a number of other issues it considered relevant.

3.5.5.1 Incentive properties

Under a WAPC, the incentive properties of the form of control depend primarily on the current structure of prices, and how quickly those prices could be expected to transition to a more "cost reflective" structure. At present, the revenues of ETSA Utilities depend primarily on electricity sales. Under a WAPC, therefore, there would remain an incentive for ETSA Utilities to expand services to high volume customers and reduce services to low volume customers. However, the application of a demand management incentive scheme is expected to balance this incentive. This issue is discussed in chapter 6 of this framework and approach paper.

Rebalancing of tariffs

A rebalancing of tariffs to closer reflect ETSA Utilities' cost structure would further mitigate some of the undesirable incentives and risks identified in ETSA Utilities' submission.[112] A pricing structure that closely matches the cost structure of a DNSP provides an environment of relatively low risk to the DNSP. It also provides an environment where the DNSP has no particular incentive to artificially distort sales towards or away from any customer group. There is some evidence that there has

[110] ETSA Utilities, *Submission in response*, op. cit., p. 14
[111] NER, cl 6.2.5(c)(5)
[112] ibid., p. 6.

been a slow rebalancing by ETSA Utilities in recent years, and ETSA Utilities has communicated to the AER its desire to undertake further rebalancing in the future.

In the long-run, theory would suggest that under a WAPC ETSA Utilities would be inclined to rebalance its tariff structure to more closely resemble its underlying costs, improving its risk and incentive properties.[113] Annual pricing proposals are expected to reveal whether such a rebalancing is occurring, and will inform the AER's decision on the form of control to apply in future regulatory control periods.[114]

Disincentives to undertake demand management

There is a concern amongst DNSPs and other stakeholders that, depending on the structure of tariffs, under a WAPC there are disincentives to undertake demand management activities which could result in a reduction in approved revenues. For this reason the NER contemplate, and the AER is likely to apply, a demand management incentive scheme that balances this incentive. The likely approach to application of a demand management incentive scheme is discussed in chapter 6 of this framework and approach paper.

3.5.5.2 Risk properties

ETSA Utilities' submission raised a number of potential issues arising from the NER side constraint and uncertainty in sales and demand growth were its current form of control to continue to apply in the forthcoming regulatory control period.

Risks to ETSA Utilities

Under the current pricing structure, ETSA Utilities' revenue is primarily driven by variable charges, whilst costs are mostly driven by factors such as network capacity and number of customer connections which are fixed in the short term.[115] Therefore, under a WAPC, ETSA Utilities will still be susceptible, at least in the short run, to risks involving variations in weather, economic growth and customer behaviour. These risks would diminish if, under a WAPC, ETSA Utilities' tariffs evolved towards more cost-reflective tariffs.

Interaction of Q-factor and the NER side constraint

ETSA Utilities expresses concern that the NER side constraint of CPI-X + 2 per cent is more restrictive than the side constraint of CPI-X + 3.5 per cent applied under the current electricity distribution price determination (EDPD). It is difficult to be definitive in this comparison given that the EDPD side constraint relates to prices of tariff components, whilst the NER side constraint relates to weighted average revenues for a tariff class. The side constraint for the forthcoming regulatory control period is nonetheless fixed and cannot be varied at the AER's discretion.[116]

If the current form of control was to be applied in the next regulatory period then the approach by the AER would be the introduction of a Q-factor carryover mechanism to allow recovery of loss revenue in the subsequent regulatory period. ETSA Utilities' argument that this would not negate exposure to short-term cash-flow issues is

[113] ibid., p. 8.
[114] ibid., p. 11.
[115] ibid., p. 7.
[116] NER, cl. 6.18.6(c)

acknowledged. However, analysis of subsequent modelling received from ETSA Utilities does not appear to demonstrate that the carryover mechanism would fail to address this issue. The modelling provided by ETSA Utilities only examines the impacts of the current form of control mechanism and does not include the proposed Q-factor carryover mechanism.

Under a WAPC this issue will no longer be relevant, because total revenues are not constrained under a WAPC and ETSA Utilities will not be required to recover or compensate consumers for forgone revenues (as required with the presence of the Q-factor mechanism).

Uncertain demand forecasts

Under a WAPC, it is likely that ETSA Utilities will have increased flexibility to manage unexpected increases in demand, as ETSA Utilities will be able to adjust tariffs to more closely reflect costs. Where this has been carried out, unexpected increases in demand which drive changes in cost (such as changes in customer numbers or peak load) would also drive changes in revenue.[117] The AER considers that this increased flexibility to meet additional costs reduces, to some extent, the risk that arises from uncertainty in sales and demand growth that ETSA Utilities raises in its submission.[118]

Risks to users

It is likely that there would be less volatility in prices within and across regulatory periods under a WAPC than the current form of control. This may provide grounds for favouring a WAPC approach.[119] As mentioned previously, a WAPC would remove the need for the under and over recovery mechanism in ETSA Utilities' current form of control, providing for less price volatility to customers within the period. Volatility across regulatory periods would also be mitigated under a WAPC. The potential for greater correlation between customer number or peak demand driven revenue and costs would allow ETSA Utilities some ability to meet the costs of additional capital. This would likely reduce the price volatility that could otherwise be experienced under the current form of control when additional capital expenditure in one regulatory period is rolled into the asset base at the commencement of the next.

Overall risk properties

When the incentive and risk properties facing both DNSPs and customers in the next regulatory control period are considered, there are grounds for favouring the WAPC approach over the current form of control.[120] While in the short-run there will still be some exposure to risk and some retention of undesirable incentives, it is likely that over time a WAPC would lead to more cost-reflective tariffs and therefore more favourable incentive and risk properties than the current form of control. However, it should be noted that the exact nature of the incentive and risk properties is largely dependent on the future structure of ETSA Utilities' proposed prices, which at this stage is still unknown.

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[117] Biggar, *Report to the AER*, op. cit., p 6.
[118] ETSA Utilities, *Submission in response*, op. cit., p. 12
[119] Biggar, *Report to the AER*, op. cit., p 10.
[120] ibid., p. 8.

The combination of this increase in flexibility and the removal of the Q-factor mechanism would also reduce the risks of price volatility to customers. It is therefore reasonable to assume that there will be improved risk properties under a WAPC relative to the current form of control. However, as noted, the actual outcomes will be dependent on the structure of ETSA Utilities' tariffs.

3.5.6 Form of control to apply to standard control services

When regard is had to the requirements of the NER, the AER considers that a transition to a WAPC would create greater benefits to both the DNSP and customers than the current form of control. These benefits are the greater probability of efficient tariff structures, and better risk and incentive properties (in conjunction with the DMIS discussed in chapter 6 of this paper) than under the current form of control. The AER has therefore decided that a WAPC will apply to standard control services in the 2010-15 regulatory control period.

3.6 Issues and AER's considerations – alternative control services

In its framework and approach paper the AER must state the form of control mechanism or mechanisms that will apply to alternative control services during the 2010-15 regulatory control period.

The factors to which the AER must have regard when deciding on the control mechanism to apply to standard control services are set out in section 3.2.3 above.

Whilst not explicitly addressing form of control, the submissions from Origin and Metropolis/Centurion discussed in chapter two of this paper develop arguments for the unbundling of metering services from the distribution use of system (DUOS) charges for greater competition in metering services.

As explained in chapter two, the AER has determined that it is likely to classify variable standard small customer metering services (type 6 metering installations), and exceptional cases of type 1-4 metering services, as alternative control services, to facilitate the proposed unbundling of metering charges. Unbundling will occur as reporting requirements for annual pricing proposals require a separation of standard control services and alternative control services tariffs. Given this likely approach, the AER must now consider the form of control mechanism that will apply to these alternative control services.

In determining the form of control that will apply, the AER must have regard to the implications of the choice of the form of control for certain key outcomes including the incentive and risk properties to which the providers and customers are exposed. As these properties are dependent on the sensitivity of the provider's profits to changes in drivers of its revenue or costs, the AER must decide on the control mechanism for alternative control services that creates the most favourable incentives and mitigates risks, whilst providing potential for the development of competition.

This framework and approach paper only considers the appropriate form of control for those variable standard small customer metering services and exceptional metering services that have been identified, in chapter two of this paper, as likely to be classified as alternative control services in the forthcoming regulatory control period. If, in its distribution determination for ETSA Utilities, the AER classifies additional services as alternative control services, a form of control for those services will be considered separately at that time.

3.6.1 The regulatory arrangements applicable in the current regulatory period

Variable standard small customer metering services (type 6 metering installations) and exceptional case (type 1-4) metering services are currently classified as prescribed services. In the 2005-10 regulatory control period, these services have been subject to the same variant of an average revenue cap (revenue yield) that applied to other prescribed services.

For the reasons outlined in section 3.5.6 above, the AER has determined that the form of control that will apply to standard control services in the forthcoming regulatory period will be a WAPC, and that the current regulatory arrangements for these services will not be continued.

3.6.2 The influence on the potential for development of competition

In deciding on a control mechanism for alternative control services, cl. 6.2.5(d)(1) of the NER requires the AER to have regard to the potential development of competition in the relevant market and how the classification might influence that potential.

3.6.2.1 Variable standard small customer metering services

As explained in section 2.5.3.3, provision of type 6 metering installations is not contestable. Under the NER, ETSA Utilities is the sole provider of these services in South Australia.[121] However, the potential exists for competition in the delivery of types 1-4 metering services, and by unbundling variable standard small customer metering services (type 6 metering installations) from the DUOS tariffs attached to standard control services by classifying these services as alternative control, potential competition by and between providers of types 1-4 metering services may increase.

As discussed above, unbundling will be facilitated by ETSA Utilities being required to submit separate annual pricing proposals for alternative and standard control services under the NER. This in itself will facilitate competition by creating greater transparency in the cost of these metering services and allowing competitors to assess prices and decide whether or not to enter the market.

It is unknown at this stage how many customers are likely to transition to an alternative type 1-4 meter due to the unbundling of meter services charges from DUOS tariffs. The AER must consider the most appropriate form of control to allow competition, whilst not placing ETSA Utilities at a disadvantage in reacting to competition.

The AER considers a WAPC the most appropriate form of control in promoting competition and enabling ETSA Utilities to deal with competition for these services. Whilst it can be argued that any control mechanism will facilitate the unbundling of meter service charges through reclassification, the AER considers that a WAPC is

[121] NER, cl. 7.2.3.

better suited as it will allow ETSA Utilities flexibility in rebalancing components of tariffs, and the ability to react to increased competition from alternative service providers.

3.6.2.2 Exceptional case metering services

The AER considers competition is unlikely to occur in exceptional case metering services, largely due to the legacy arrangements for these services. As explained in section 2.5.3.3, due to the possible duplication of costs that would be associated with reclassifying exceptional case metering services as negotiated distribution services (which are subject to a 'negotiate-arbitrate' framework rather than a direct control on prices or revenue), the AER considers that these services are more appropriately retained under a direct control classification.

The AER considers that the unbundling of exceptional case metering services from DUOS tariffs by classifying them as alternative, rather than standard, control services may influence competition if a competitor considers it is able to provide a newer meter at a competitive price. However, it is likely that competition within this market will be minimal. Therefore, the AER considers that there are no grounds to favour one form of control over another in regards to potentially developing competition for exceptional case metering services.

3.6.3 Administrative costs

The AER recognises that the control mechanism implemented should minimise the complexity and administrative burden for the AER, the DNSP and users without compromising the effectiveness of the constraint.

The application of a WAPC to both variable standard small customer metering services and exceptional case metering services is consistent with the control mechanism applied to standard control services, and would, but for the decision to unbundle the charges for these services from DUOS charges, have been applied to these services in the forthcoming regulatory period. The AER considers that this approach will present lower additional administrative costs than applying a different form of control to standard and alternative control services.

The AER recognises that the reclassification of these services as alternative control services and the application of a WAPC form of control will potentially result in some additional administrative costs to ETSA Utilities, which will in turn be passed on to users of those services. Such an increase is expected to be largely transitional in nature, so that administrative costs are likely to reduce over time. However, the AER is satisfied that the benefits arising from the potential increase in competition for metering services for variable standard small customer metering services and the efficiency reasons for unbundling DUOS tariffs for exceptional case metering services outweighs the associated administrative costs.[122]

3.6.4 The desirability of consistency

In deciding on a control mechanism for alternative control services, the AER must have regard to the desirability of consistency between regulatory arrangements for similar services, both within and beyond the relevant jurisdiction.

[122] NER, cl 6.2.5(d)

As noted above, while consistency between jurisdictions in the medium to long term may be desirable, the AER does not consider that consistency in the form of control applied across jurisdictions should be determinative in selection of a form of control at this time. The AER notes that different forms of control are applied to alternative control services across the NEM for alternative control services.

The AER considers that consistency for alternative control services within a jurisdiction is also desirable. The application of a WAPC to both variable standard small customer metering services and exceptional case metering services would provide a consistent approach between standard and alternative control services.

For the reasons outlined in chapter two, the AER does not consider that either of these services can appropriately be classified as negotiated distribution services. As a result the negotiate-arbitrate framework that will, under the likely approach to service classification, apply to non-standard small customer metering services (meters meeting the requirements of type 1-4 metering installations provided to small customers), type 5 metering installation services and large customer metering services (type 1-4 metering services provided to large customers) is not available.

3.6.5 Other relevant factors

In addition to the issues discussed above, the NER require the AER to consider any other factor it considers relevant in deciding on a form of control for alternative control services.[123] As discussed in section 3.5.5 above, the incentive and risk properties of a form of control are relevant to the AER's decision.

3.6.5.1 Incentive properties

The AER considers it desirable to apply the control mechanism that provides the most favourable incentive properties. In relation to variable standard small customer metering services and exceptional case metering services the AER notes that the exact nature of these incentives (or risks) are unknown until the proposed structure of prices is known. However, through applying a WAPC to these services there is little scope for undesirable incentives. The primary objective for reclassifying these services is to encourage the unbundling of metering services charges from current DUOS tariffs.

Incentives for efficient pricing

Where competition exists, theory suggests that under a WAPC providers have the greatest incentive to choose efficient prices where the structure of prices reflects the structure of costs. The drivers for metering services costs and the drivers for metering services revenues are both directly attributable to customer numbers. While in practice it is not certain that efficient prices will emerge, there is a greater likelihood of an efficient pricing structure as revenues are directly related to costs. As customers are sensitive to pricing signals, providers have further incentives to seek efficient prices as they compete for their business. Customers can benefit under these conditions as providers, including ETSA Utilities, seek these efficient prices as they compete.

[123] NER, cl 6.2.5(c)(5)

3.6.5.2 Risk properties

The AER also considers it desirable to apply a control mechanism that best mitigates risks to both ETSA Utilities and its customers.

Risks to providers

Variable standard small customer metering services

As it is unknown at this stage how many customers are likely to transition to an alternative type 1-4 meter due to the unbundling of meter services charges from DUOS tariffs, the AER must consider the risks to providers for incorrectly forecasting customer numbers.

A WAPC best mitigates the risk to providers of unforeseen discrepancies between forecast and actual customer numbers. Unlike a revenue cap, for example, where providers face a risk if actual numbers are significantly different to that forecast, a WAPC insulates the providers of metering services against such risks, since revenue is directly attributable to the costs of providing these services. If actual customer numbers exceed those forecast, then the provider of these services is not constrained by the allowable revenue and can offset the cost of providing these additional services.

Exceptional case metering services

Due to the legacy arrangements for the exceptional case metering services there is considerably less risk facing ETSA Utilities, as these services are dependent on customer numbers which are known and unlikely to change. This would be consistent under all control mechanisms as there would be little if any discrepancy between forecast and actual customer numbers. However, in the event that customers consider a transition to the competitive market, a WAPC would be favoured as it gives ETSA Utilities the flexibility to restructure its prices at a competitive level.

Risks to users

Variable standard small customer metering services

As discussed above, the provider of variable standard small customer metering services is insulated against the risk of discrepancies between forecast and actual customer numbers under a WAPC. The close relationship between the cost drivers and revenue drivers ensures that the provider is not as affected by demand as they would be under a revenue cap control mechanism. This ability to meet additional costs reduces the likelihood of price volatility to customers as there is no over or under recovery mechanism of allowable revenue.

Exceptional case metering services

Again as discussed above, there are some risks to exceptional case metering services customers under a revenue, as distinct from a price, control. For example, in the event that customers consider a transition to newer meters, the remaining customers may be exposed to price shocks under a revenue cap, as ETSA Utilities would have to recover the lost revenue from the customers remaining on the exceptional case meters. The AER considers that a WAPC control mechanism mitigates this risk to users as ETSA Utilities would able to make adjustments to its prices as customers replace their meters, and is therefore preferable to a revenue cap.

3.6.6 Form of control to apply to alternative control services

On the basis of the AER's likely approach to classification of variable standard small customer metering services and exceptional case metering services as alternative control services, the AER will require ETSA Utilities to apply a WAPC as the form of control for these services. This will enable the unbundling of ETSA Utilities' metering service charges from their DUOS tariffs, which the AER considers will also facilitate the potential for development of competition in variable standard small customer metering services.

3.7 Form of control mechanisms to be applied by the distribution determination

3.7.1 Standard control services

Having considered ETSA Utilities' submission, the AER agrees that there are grounds for applying a WAPC form of control to ETSA Utilities' standard control services in the 2010-15 regulatory period in place of its current form of control.

The AER's decision on the transition to a WAPC for standard control services has been based on the following considerations:

- Whilst the preliminary position of retaining the current form of control for standard control services with the addition of some minor variations satisfies the requirements of the NER,[124] the AER agrees with ETSA Utilities' submission there are a number of deficiencies in the current form of control that make it undesirable to implement in the next regulatory period.
- It is unclear to the AER that any form of control imposed on ETSA Utilities is guaranteed to result in efficient tariff structures; however the AER considers that it is more likely to occur under a WAPC than under the current form of control.[125]
- The AER acknowledges that a transition to a WAPC may simplify some administrative costs vis-à-vis ETSA Utilities' current form of control, but considers there are no clear grounds for favouring the WAPC over the current form of control on this basis.[126]
- Consistency in the form of control applied across jurisdictions is not considered by the AER as determinative in selection of a form of control at this time.[127] However, as a general rule, the AER considers it desirable that a WAPC be applied consistently to all standard control services within South Australia.
- In addition to the matters set out above, in deciding on the form of control the NER requires the AER to have regard to any other relevant factor.[128] The AER considers the incentive and risk properties associated with a form of control to be a significant and defining factor in the selection of form of control for standard control services. The AER considers that, overall, the incentive and risk properties

[124] NER, cl 6.2.5(c)(3)
[125] NER, cl 6.2.5(c)(1)
[126] NER, cl 6.2.5(c)(2)
[127] NER, cl 6.2.5(c)(4)
[128] NER, cl 6.2.5(c)(5)

under a WAPC are more favourable to stakeholders than the current form of control.

The WAPC control mechanism will be of the CPI – X form, and will include adjustments to incorporate any revenue increment or decrement associated with the application of the STPIS and DMIS discussed in chapters 4 and 6 of this framework and approach paper, and the undergrounding allowance required under the EPO. An additional adjustment will apply to allow ETSA Utilities to carry forward impacts associated with the calculation of Maximum Average Distribution Revenue under the 2005-10 EDPD into the 2010/11 and 2011/12 regulatory years, as required by cl. 9.29.5(b)(2).

The WAPC that will apply to ETSA Utilities' standard control services is set out in appendix D to this framework and approach paper.

3.7.2 Alternative control services

Having had regard to the requirements of cl. 6.2.5(d) of the NER, the AER has concluded that the form of control that will apply to ETSA Utilities' alternative control services for the 2010-15 regulatory control period will be a WAPC. Due to the differing nature of variable standard small customer metering and exceptional case metering services, separate tariff classes and tariff components will apply to the formulation of their respective caps.

The AER's decision to apply a WAPC to variable standard small customer metering services and exceptional cases of (type 1-4) metering services has been based on the following considerations:

- The departure from the current form of control for standard control services and the reclassification of these services requires the AER to analyse the appropriateness of its application to alternative control services.[129] The AER considers a consistent form of control to that applied to standard control services should be applied for variable small customer metering services and exceptional cases of (type 1-4) metering services in the next regulatory control period.
- Through reclassifying the provision of variable small customer metering services as alternative control services the AER considers that the promotion of competition is likely to occur, allowing for providers of type 1-4 metering services to compete for these services.[130] The AER considers that a WAPC is the best form of control to enable ETSA Utilities to react to competition in variable standard small customer metering services.
- The AER considers that it is unlikely that any form of control would reduce barriers to entry and promote competition for exceptional case metering services.[131] However, the AER considers that for efficiency reasons, the objective to remove these metering services charges from DUOS tariffs through reclassifying the provision of these services as alternative control services is appropriate.

[129] NER, cl 6.2.5(d)(3)
[130] NER, cl 6.2.5(d)(1)
[131] NER, cl 6.2.5(d)(1)

- A transition to a WAPC under a new classification has the potential to result in some additional administrative costs to the AER, ETSA Utilities and users.[132] By subjecting these services to the same control mechanism as standard control services, the AER considers the comparable administrative costs are more favourable under a WAPC than other form of control mechanisms for these services.
- The AER notes that there is currently no consistent application of forms of control across jurisdictions. However, the application of a WAPC to variable standard small customer metering services and exceptional cases (type 1-4) metering services provides for a consistent approach within the jurisdiction, which the AER considers desirable. [133]
- In addition to the matters set out above, in deciding on the form of control the NER requires the AER to have regard to any other relevant factor.[134] The AER considers the incentive and risk properties a significant and defining factor in the selection of form of control for variable standard small customer metering services. The AER considers the overall incentive and risk properties under a WAPC to be more favourable to stakeholders than the other control mechanisms for variable standard small customer metering services and for exceptional case metering services.

The basis of control mechanism for variable standard small customer metering services and exceptional case metering services will be a variant of the CPI – X form applied to standard control services.

The WAPC that will apply to each of these services is set out in appendix D to this form of control paper.

[132] NER, cl 6.2.5(d)(2)
[133] NER, cl 6.2.5(d)(4)
[134] NER, cl 6.2.5(d)(5)

4 Application of service target performance incentive scheme

4.1 Introduction

This chapter discusses the likely approach to application of the service target performance incentive scheme (STPIS) to ETSA Utilities in the regulatory control period commencing 1 July 2010.

The STPIS provides incentives to maintain and improve service performance. The incentive regulation framework provides DNSPs with an incentive to reduce costs where practical. In a situation where service performance is maintained or improved, cost reductions are beneficial to both the DNSP and its customers. However, cost efficiencies achieved at the expense of service levels experienced by customers are not desirable. The STPIS establishes targets based on historical levels of performance, and provides incentives to meet or exceed them by attaching rewards and penalties to performance above or below the targets.

4.2 Requirements of the National Electricity Rules

The NER require the AER to include in its distribution determination a decision on how the STPIS will apply to the DNSP for the relevant regulatory control period.[135] The AER's framework and approach paper must set out the AER's likely approach to the application of a STPIS in its forthcoming distribution determination.[136]

4.2.1 AER's distribution STPIS

The AER released the national distribution STPIS on 26 June 2008. The STPIS is available on the AER's website, www.aer.gov.au.

4.2.2 Structure of the STPIS

The STPIS has four components:

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

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

[135] NER, cl. 6.3.2 (a) (3)
[136] NER, cl. 6.8.1 (b) (2)

4.2.2.1 S-factor

The first three components of the STPIS 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 (in the form of a revenue increment or decrement) for exceeding or failing to meet predetermined targets. The maximum revenue at risk under the s-factor is ± 3 per cent of a DNSP's revenue for each year of the regulatory control period.[137]

Reliability of supply component

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

- Unplanned system average interruption duration index (SAIDI)
- Unplanned system average interruption frequency index (SAIFI), and
- Momentary average interruption frequency index (MAIFI).[138]

Performance targets for these parameters are based on a DNSP's average historical performance over the last five years.[139] 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
- 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.

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[137] The AER retains discretion under the STPIS to alter this figure where doing so would achieve the objectives set out in cl. 6.6.2 of the NER.

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

[139] This data is adjusted where necessary to account for improvements in reliability which have been included in the DNSP's expenditure program, and adjusted for any other material factors expected to affect network reliability performance: targets will not necessarily be equal to average performance over the previous five years.

As with reliability of supply, customer service performance targets are based on average performance over the previous five years.[140] Unlike targets for the reliability of supply component of the STPIS, targets for this component apply to the distribution network as a whole, and different targets are not set for different segments of the network.

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 report its performance against all applicable parameters in each year.[141]

4.2.2.2 Guaranteed service levels (GSL)

The purpose of a GSL scheme is to provide payments to individual customers if the level of service they experience falls below a predetermined level. The GSL scheme can operate independently, or concurrently with the s-factor scheme. The AER will not apply the GSL component of the STPIS to DNSPs while they remain subject to a jurisdictional GSL scheme.

4.2.3 Implementing the STPIS

The STPIS facilitates 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:[142]

- 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 regulatory obligation or requirement to which the DNSP is currently subject
- the past performance of the distribution network
- any other incentives available to the DNSP under the NER or a relevant distribution determination
- the need to ensure that the incentives are sufficient to offset any financial incentives the DNSP may have to reduce costs at the expense of service levels
- the willingness of the customer or end user to pay for improved performance in the delivery of services
- the possible effects of the scheme on incentives for the implementation of non-network incentives.

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140 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. Again, targets will not necessarily be equal to average performance over the last five years.

141 These reporting requirements relate to the application and operation of the STPIS under the distribution determination by which it is applied. Additional annual reporting requirements may apply to a DNSP.

142 NER, cl. 6.6.2(3).

The AER must also:

- consult with the authorities responsible for the administration of relevant jurisdictional electricity legislation[143]
- 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.[144]

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

The AER's preliminary position was that it was likely to apply the reliability of supply and customer service components of the STPIS to ETSA Utilities in the 2010-15 regulatory control period.

Under the reliability of supply component, the AER proposed that targets be set for both SAIDI and SAIFI, with financial incentives attached to each, and that ETSA Utilities' network be divided into four feeder types (CBD, Urban, Short Rural and Long Rural) identified in the STPIS for this purpose. The preliminary position was that the sampling technique currently used by ETSA Utilities to record MAIFI in the current control period was not suited to an incentive mechanism such as the STPIS, so that insufficient data was available to include MAIFI as a STPIS parameter for ETSA Utilities in the 2010–15 regulatory control period.

The preliminary position was that the telephone answering parameter of the customer service component (as defined in appendix A of the STPIS) was likely to apply to ETSA Utilities for the forthcoming regulatory control period.

The GSL component of the STPIS will not apply to ETSA Utilities in the forthcoming regulatory control period while the current GSL scheme administered by ESCOSA remains in place.

4.4 Summary of submissions

ETSA Utilities was the only stakeholder to make a submission on the likely approach to the application of the STPIS in its 2010–15 regulatory control period.

That submission agrees with the proposal to apply only the reliability of supply and customer service components of the STPIS to ETSA Utilities in the forthcoming regulatory control period, and with the parameters proposed. ETSA Utilities also agrees with application of the Value of Customer Reliability (VCR) based incentive rate in the STPIS, and the basis for setting baseline performance targets outlined in the scheme.

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[143] NER, cl. 6.6.2(b)(1)

[144] 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.

In addition to the matters discussed in the preliminary positions paper, ETSA Utilities also raises a number of issues which it considers necessitate a different application of the STPIS to that set out in the preliminary positions paper. These issues are set out below.

4.4.1 Incentive Cap

ETSA Utilities submits that the s-factor component of the STPIS should be capped at ±1 per cent of total revenue, rather than ±3 per cent. Within this ±1 per cent cap, it submits that the maximum incentive for the customer service component (with its single telephone answering parameter) should be ±0.05 per cent of revenue, rather than ±0.5 per cent.

In support of this position, ETSA Utilities submits that:

- The Service Incentive Scheme (SI Scheme) applied by ESCOSA in the current period limits its financial exposure to $2.1 million per year (which ETSA Utilities equates to approximately 0.4 per cent of its current total annual revenue).

- Under the current incentive regime, reliability has been maintained for those customers included in the scheme and there has been an improvement in the customer service measure. According to ETSA Utilities, the current incentive has been sufficient to offset any financial incentives it may have to reduce costs at the expense of service levels, and therefore satisfies cl. 6.6.2(b)(3)(v) of the NER.

- The cap applied to the current incentive scheme was based on customer willingness to pay surveys undertaken in 2002 and 2007, both of which confirmed that 85 per cent of customers were happy with current levels of reliability and were unwilling to pay for improved levels of service. ETSA Utilities considers that the 3 per cent incentive put forward in the AER's preliminary positions paper is not warranted under cl. 6.6.3(b)(3)(vi) of the NER, as it would exceed its customers' willingness to pay.[145]

4.4.2 Reliability of supply exclusions

The STPIS excludes from the calculation of a DNSP's reliability performance any day (measured from midnight to midnight) where daily unplanned SAIDI for the electricity distribution network exceeds the major event day threshold. This threshold is calculated using the methodology set out in the Institute of Electrical and Electronics Engineers Standard 1306-2003 (IEEE standard) which uses the natural log to convert daily SAIDI into a normal distribution to which statistical measures are applied to remove outliers in performance.

ETSA Utilities has expressed concern that its daily SAIDI data does not produce a normal distribution using the natural logarithm assumed in the application of the IEEE standard.

ETSA Utilities submitted a report from Dr John Field, which analyses the effect of applying the IEEE standard to ETSA Utilities' SAIDI data. Dr Field's report states:

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[145] ETSA Utilities: *Submission to the AER's Preliminary Positions Paper on the Framework and Approach for ETSA Utilities 2010–15,* p. 17

> We can calculate the skewness and kurtosis for log (SAIDI). The skewness is a measure of the symmetry of the distribution, and kurtosis is a measure of whether the distribution is peaked or flat relative to the normal distribution. For the normal distribution we would expect both to be zero. For this data, skewness = -0.321 with a 95 per cent confidence interval of (-0.466 to -0.176). The kurtosis is 0.604 with a confidence interval of (0.314 to 0.894).
>
> …
>
> We also use the Anderson –Darling test to test for normality. This test is one of the most powerful for testing for departure from normality….The usual statistical practice is to reject the hypothesis that the data comes from a normal distribution if the significance probability is less than 0.05; for the ETSA Utilities data, the test gives a significance probability of P=0.0006; that is, there is a chance of only 6 in 10,000 that the log (SAIDI) data come from a normal distribution.[146]

The report concludes that the distribution of log (SAIDI) differs from the normal distribution.[147] As a result, ETSA Utilities submits that the statistical methodology used to define major event days in the IEEE Standard is not appropriate for ETSA Utilities[148], and proposes two alternative methodologies for calculating exclusions under the reliability of supply component:

- IEEE methodology, however, applying a rolling two day period
- Box-Cox conversion (which does not use the natural logarithm of daily SAIDI).[149]

ETSA Utilities has modelled reported reliability data for the last three financial years to illustrate the application of these two methodologies. ETSA Utilities submits that "the overall distributor wide variability" in annual SAIDI when the IEEE standard is applied is 17.6 per cent, compared to 9.8 per cent using the two consecutive day method, and 11.8 per cent using the Box-Cox method.

In support of its submission, ETSA Utilities provided an example of how it considers the IEEE standard would apply in the case of an extreme weather event,[150] using data from weather related interruptions on 19 and 20 January 2007, in which the first interruption occurred at 00:36 on 19 January, and ceased with the commencement of the last weather related interruption at 01:09 on 21 January. The last interruption was restored at 02:07 on 21 January.

The table below shows the statistics related to the event using ETSA Utilities' current reporting methods.

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146 John Field Consulting: Defining Major Event Days (produces for ETSA Utilities), p. 4

147 ibid

148 ETSA Utilities: *Submission to the AER's Preliminary Positions Paper on the Framework and Approach for ETSA Utilities 2010–15,* p. 24

149 ibid., p. 21

150 According to ETSA Utilities, severe weather events in South Australia are characterised by cold fronts moving through, traversing from the west of the state or the east of the state, and lightning storms that traverse from the north of the state to the south east of the state. See footnote 17.

Table 4.1: ETSA Utilities – example severe weather event

	19 January 2007	20 January 2007	Total
SAIDI	4.9	5.7	10.5

Source: ETSA Utilities [151]

Using this data, ETSA Utilities submits that the IEEE threshold would be 6.013 minutes, so that neither day would be classified as a major event day. In contrast, both days exceed the Box Cox threshold of 4.330 minutes, and (when combined) the two consecutive day threshold of 6.887 minutes.

On this basis, ETSA Utilities submits that the major event day threshold adopted in the STPIS exclusion should not be applied, as it does not correctly identify severe weather events in South Australia.

4.4.3 Capped incentives and uncapped performance targets

Using actual unplanned high voltage reliability performance for the period 2000–01 to 2007–08,[152] ETSA Utilities has undertaken modelling based on the STPIS for two reliability performance scenarios:

1. a situation where there is no improvement in performance, that is, performance is maintained, and
2. a situation whereby performance is improved by 1 minute per year from 2001-02 to 2007-08 (a 7 minute total improvement).

To each scenario, the modelling applies two exclusions:

a. Standard IEEE MED days, and

b. ETSA Utilities' proposed two consecutive day method.

[151] ETSA Utilities: *Submission to the AER's Preliminary Positions Paper on the Framework and Approach for ETSA Utilities 2010–15,* p. 23

[152] ETSA Utilities notes in its submission that data from 2000/01 to 2007/08 has been used for modelling purposes, as only three years of OMS data is available.

The results of ETSA Utilities' modelling are summarised in table 4.2 below:

Table 4.2: Results of ETSA Utilities scenario modelling for reliability of supply

Scenario	Initial Target	Final target	Uncapped ($m)	1 per cent cap ($m)	3 per cent cap ($m)
1 (a)	139.2	139.2	0	-45	-36
1 (b)	130.2	130.2	0	-30	0
2 (a)	139.2	132.2	28	-37	-20
2 (b)	130.2	123.2	28	-22	28

Source: ETSA Utilities[153]

ETSA Utilities submits that using the IEEE exclusion adopted in the STPIS under a cap of ±1 per cent or ±3 per cent results in a perverse outcome whereby it is penalised for maintaining or improving performance.

By contrast, ETSA Utilities submits that if its two-consecutive day exclusion criterion is adopted the STPIS would result in penalty under the 1 per cent incentive cap for maintaining or improving performance, and that using a 3 per cent cap would have the same result as uncapping the incentive completely.[154]

ETSA Utilities proposes two potential remedies:

- uncapping the STPIS, so that there is no fixed limit to the revenue at risk under the scheme, or
- linking the current year's target to the previous year's target, but making an adjustment for the incentive actually received by ETSA Utilities.

ETSA Utilities considers the latter to be the best approach, noting that this would necessitate a cap for each parameter under the scheme, summing to the total cap for the STPIS.

4.5 Issues and AER's considerations

The preliminary position was to apply a STPIS to ETSA Utilities for the 2010–15 regulatory control period.

Under the s-factor scheme, SAIDI and SAIFI would be applied as parameters under the reliability of supply component, and telephone answering (as defined in appendix C of the STPIS) would apply under the customer service component. No quality of supply parameters were proposed in the preliminary positions paper. The preliminary position was not to apply a GSL scheme to ETSA Utilities in the 2010–15 regulatory

153 ETSA Submission, p. 25.

154 ETSA Utilities notes that reliability volatility using the OMS data and either the 2 day consecutive exclusion or the Box-Cox methodology produces similar variability to the IEEE standard using HV reliability data, and that this will ultimately result in ETSA Utilities reaching the 3 per cent cap during the regulatory period.

control period whilst ETSA Utilities remains subject to a jurisdictional GSL scheme administered by ESCOSA.

For the purposes of setting targets for SAIDI and SAIFI, the preliminary position was that the South Australian distribution network should be segmented according to feeder type (CBD feeder, Urban feeder, Short rural feeder, Long rural feeder).

ETSA Utilities' submission accepts all of these positions.

Those aspects of the preliminary positions paper that ETSA Utilities does not accept are discussed below.

4.5.1 Incentive cap

The STPIS proposes a default maximum revenue increment or decrement for the STPIS, excluding GSL components, of ±3 per cent of total revenue for each regulatory year. The preliminary positions paper proposed application of this default ±3 per cent cap to ETSA Utilities. Within this cap, the STPIS provides that the maximum revenue at risk for any one customer service parameter will be ±0.5 per cent. This was the cap proposed for the telephone answering parameter.

4.5.1.1 Current incentive cap

In its submission in response to the preliminary positions paper, ETSA Utilities claims that under the Service Incentive Scheme (SI Scheme) applied by ESCOSA in the current control period the incentive applied is $2.1 million per annum, which represents about 0.4 per cent of its revenue, comprising approximately 0.3 per cent for reliability performance and 0.1 per cent for customer service (telephone response).

ETSA Utilities proposes that the incentive cap under the STPIS should be in the range ±0.4 per cent to 1.0 per cent, and recommends ±1 per cent, which it claims is approximately 2.5 times the current incentive cap. ETSA Utilities proposes that, within this limit, the maximum revenue at risk for the telephone answering measure under the customer service parameter should be limited to ±0.05 per cent of revenue.

ESCOSA's SI Scheme caps revenue at risk, so that:

- the reliability measure will be capped at $30 million (from a potential financial incentive for the reliability measure of $45 million), which represents about ±1.3 per cent of ETSA Utilities' prescribed distribution revenue over a five-year period, and
- the total financial incentive for the customer service measure would be $7.5 million, or about 0.3 per cent of ETSA Utilities' prescribed distribution revenue over a five-year period.

This limits the total financial incentive under the SI Scheme to ±$37.5 million, which ESCOSA claims represents about 1.6 per cent of ETSA Utilities' prescribed distribution revenue.

Unlike the STPIS, which aims to send a whole-of-network signal, ESCOSA's SI Scheme is designed to provide financial incentives for ETSA Utilities to improve reliability service to only the worst served customers, comprising approximately 15 per cent of ETSA Utilities' customer base.[155] Effectively, this revenue at risk is limited to serving the worst performing feeders in the South Australian distribution network at a point in time. When the financial exposure under the two schemes is compared, it should be noted that the schemes serve different purposes, and consequently require different incentive properties. The AER's scheme, whilst placing more revenue at risk, targets the entire South Australian distribution network. The AER therefore considers it appropriate to subject ETSA Utilities to a higher financial exposure, given the greater scope of the scheme.

4.5.1.2 Incentive properties of the STPIS

ETSA Utilities further submits that in the current period reliability performance for customers included under the SI scheme has been maintained and customer service has improved, and that this demonstrates that the current incentive cap has been sufficient to maintain or improve performance.

Performance reports published by ESCOSA for 2005–06 and 2006–07 show that, overall, performance against targets set under the SI scheme and ETSA Utilities' average service standards has been variable in the current period.

ETSA Utilities' customer service performance under the SI scheme for the 2005 calendar year was 85.5 per cent. This was lower than the 86 per cent threshold for the first bonus point under the scheme, so that no bonus points were earned. [156] Customer service performance under the SI scheme for the 2006 calendar year was 87.4 per cent, 2.7 per cent better than the target of 85 per cent. This resulted in a two point bonus.[157]

Under the SI scheme, the reliability target for the reporting period ending 31 December 2005 was 77.1 minutes. Outturn performance was 72.6 minutes, earning ETSA Utilities a 1 point bonus under the SI Scheme.[158] However, the reliability target for the following reporting period was 74.6 minutes and performance was 90.2 minutes, which resulted in ETSA Utilities receiving a three point penalty.[159]

The reliability target for the reporting period ending 31 December 2007 was set at 82.1 minutes. The adjusted customer service performance target for the 2007 calendar year is 87 per cent. Results for that year have not yet been published by ESCOSA.

ETSA Utilities' performance in the current period has also been monitored against average service standards set by ESCOSA for seven defined geographic regions.

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155 This approach was predicated on the outcomes of a consumer survey which revealed that around 85 per cent of consumers were satisfied with their level of service and were unwilling to pay for improvements in these levels. ESCOSA reports that the number of customers connected to feeders that qualified for the SI Scheme because of poor performance between 2002 and 2006 ranged from 14 per cent to 19 per cent, close to the 15 per cent suggested in the development of the SI scheme as being the appropriate proportion of customers to be targeted by the scheme.

156 ESCOSA, *2005/06 Annual Performance Report – Performance of South Australian Energy Network Businesses*, November 2006, p. 68

157 ESCOSA, *2006/07 Annual Performance Report – Performance of South Australian Energy Networks*, November 2007, p. 59

158 ESCOSA, *2005/06 Annual Performance Report – Performance of South Australian Energy Network Businesses*, November 2006, p. 67

159 ESCOSA, *2006/07 Annual Performance Report – Performance of South Australian Energy Networks*, November 2007, p. 58

Table 4.3: ESCOSA geographic regions compared with SCONRRR feeder types.

Geographic region	Feeder type*
Adelaide business area	All CBD
Barossa/Mid North and Yorke Peninsula/ Riverland/Murrayland	Approximately two thirds rural long; one third rural short
Eastern Hills/Fleurieu Peninsula	Approximately one third rural long; two thirds rural short
Major metropolitan areas	Mostly urban, with some rural long and rural short
South East	Mostly rural long with some rural short
Upper North and Eyre Peninsula	Mostly rural long with some urban and rural short
Kangaroo Island	Limited to rural long

Source: ETSA Utilities 13 June 2008.
* Correlation of feeder types to geographic regions are approximations only.

Performance against average service standards for each region is summarised below:

Table 4.4: ETSA Utilities performance against average service standards 2005-2007

Year	Performance against targets
SAIDI	
2005–06	SAIDI targets were only met in three of the seven regions (Adelaide Business Central and South East). Total network SAIDI was 22 per cent higher than the target and 8 per cent higher than the previous highest value for this measure (recorded in 2000/01).
2006–07	SAIDI performance for the distribution network was generally worse than the annual targets. Whilst performance for the Major Metropolitan Areas was only 3 per cent worse than the target SAIDI performance in the Upper North & Eyre Peninsula and South East regions was 30 per cent and 48 per cent worse than the targets respectively. Total network SAIDI was 12 per cent worse than the target though an 8 per cent improvement from 2005–06 was noted.
SAIFI	
2005–06	SAIFI targets were only met in three regions (Adelaide Business Central and South East). Total network SAIFI was 11 per cent higher than the average target.
2006–07	ETSA Utilities performed better than targets in four of the six regions for which such targets had been set. Performance in the Major Metropolitan Areas and South East region was worse than the targets by 5 per cent and 40 per cent respectively. However, total network SAIFI was 3 per cent better than the target and 9 per cent better than performance in 2005–06.

Source: ESCOSA[160]

ETSA Utilities has exceeded its current average service standard (85 per cent of all calls to be answered in 30 seconds) for telephone answering in each year for which data is available, and performance has improved from 86.9 per cent of calls in 2004/05 to 89.3 per cent in 2006/07. However, performance slipped to 85.2 per cent in 2005/06. Results for the 2007/08 financial year are not yet available.

On the basis of available performance data from the current period, the AER is not satisfied that ETSA Utilities has established that an incentive cap of 1 per cent (and within that 0.05 per cent for telephone answering) is sufficient to offset any incentives it may have to reduce costs at the expense of service levels in the forthcoming regulatory control period, and create an incentive to maintain or improve performance.

4.5.1.3 Customer willingness to pay

ETSA Utilities considers that the 3 per cent incentive put forward in the preliminary positions paper is not warranted under clause 6.6.3(b)(3)(vi) of the NER, as it would exceed its customers' willingness to pay. ETSA Utilities also cites customer willingness to pay in support of its argument that that 0.5 per cent revenue at risk for

160 ESCOSA: Annual Performance Reports: Performance of the South Australian Energy Distributors http://www.escosa.sa.gov.au/site/page.cfm?u=27&c=47

customer service measures is not appropriate. In support of this claim, ETSA Utilities submits that the incentive cap applied to the current ESCOSA SI scheme is based on the results of customer willingness to pay surveys undertaken in 2002 and 2007, both of which confirmed that 85 per cent of customers were happy with current levels of reliability and were unwilling to pay for improved levels of service.

It is the incentive rates under the AER's STPIS that reflect customer willingness to pay, rather than the caps placed on revenue at risk. The latter is imposed to ensure that the incentives under the STPIS are sufficient to offset any financial incentives ETSA Utilities may have to reduce costs at the expense of service levels.[161]

Application of VCR-based incentive rates ensures that penalties and rewards under the STPIS are commensurate with the willingness of customers or end users to pay for improved performance in the delivery of services,[162] regardless of where the cap on revenue at risk is set. It also ensures that the benefits to consumers resulting from the scheme are sufficient to warrant the reward paid to, or penalty paid by, ETSA Utilities for its performance relative to historical levels.[163] ETSA Utilities has, in its submission, accepted the incentive rates set out in the STPIS. The AER received no submissions from ETSA Utilities' customers or end users suggesting that these incentive rates are not reflective of their willingness to pay.

The incentive rates contained in section 3.3.2 of the AER's STPIS were based on the most recent and robust study on customers' willingness to pay for improved performance at the time the STPIS was published.[164] The AER is aware that VENCorp has commissioned a new VCR study[165], the results of which may supersede the values in the 2002 study applied in the AER's STPIS.

The AER encourages ETSA Utilities to have regard to this new study when developing its regulatory proposal, and invites ETSA Utilities' customers and end users to consider, when making submissions on that proposal, whether incentive rates based on this new study would better reflect their willingness to pay for improvements in service performance. In making its distribution determination for ETSA Utilities, the AER will have regard to the results of this latest study in deciding how the STPIS will apply in the 2010-15 regulatory control period.

4.5.1.4 Conclusion

For the reasons set out above, the AER is not satisfied that the lower incentive cap of ±1 per cent of total revenue proposed by ETSA Utilities is appropriate when regard is had to the criteria in cl. 6.6.2(b)(3) of the NER. The AER's likely approach is therefore to apply the default incentive cap of ±3 per cent to ETSA Utilities in its distribution determination for the forthcoming regulatory control period, and within that a cap of ±0.5 per cent on the telephone answering parameter applied under the customer service component of the scheme.

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161 NER, cl. 6.6.2(b)(3)(v)
162 NER, cl. 6.6.2(b)(3)(vi)
163 NER, cl. 6.6.2(b)(3)(i)
164 Charles River Associates, 2002, *Assessment of the Value of Consumer Reliability (VCR) – report prepared for VENCorp*.
165 CRA International, *Assessment of the Value of Customer Reliability (VCR)*, 12 August 2008.

4.5.2 Reliability of supply exclusions

The major event day exclusion in the STPIS is drawn from the IEEE standard (commonly referred to as the 2.5 beta method).

To classify a major event day, this exclusion:

1. Takes the five most recent years of historical values of unplanned SAIDI/day
2. Finds the natural logarithm of each value in the data set (*ln(SAIDI)*)
3. Calculates the average (α) and standard deviation (β) of the new data set
4. Calculates the major event day threshold (TMED) as TMED = exp (α + 2.5β)

Any day on which SAIDI is greater than TMED is classified as a major event day.

ETSA Utilities submits that the 2.5 beta method contained in the IEEE standard is not appropriate for calculating exclusions for the South Australian distribution network, because a normal distribution is not produced when transforming its daily SAIDI by using the natural logarithm in step two.[166]

The information provided by ETSA Utilities in response to the AER's preliminary positions paper indicates that, when step two is applied, its SAIDI data is negatively skewed, and not normally distributed. Whether or not this poses a long term problem for the application of the IEEE exclusion methodology to ETSA Utilities depends on whether the data is expected to continue to be distributed in this manner, or to move toward a normal distribution as the data set grows. If the true distribution of the *ln(SAIDI)* data is normal, the *ln(SAIDI)* data will tend to become normally distributed over time.

However, if as ETSA Utilities suggests the underlying distribution of its *ln(SAIDI)* data is not normal, then the Box-Cox methodology proposed by ETSA Utilities may partially remedy this issue.

The Box-Cox transformation is an alternative method of transforming SAIDI data into a normal distribution, which would stand in place of the log taken in step two of the IEEE exclusion. This transformation seeks to convert raw daily SAIDI data into a normal distribution through application of a formulaic adjustment, the parameters of which are selected to give the best fit with a normal distribution.

On the basis of the historical performance data provided to ETSA Utilities' consultant, the Box-Cox methodology appears to create a more accurate method for converting ETSA Utilities' raw SAIDI data into a normal distribution. For example, while still slightly more peaked than a normal distribution, the distribution is symmetrical. This would, if correct, facilitate an application of the remaining steps of the IEEE exclusion to ETSA Utilities that is consistent with its intended operation and provides greater consistency with its application to other DNSPs.

ETSA Utilities has also argued that the 2.5 beta method does not apply well in South Australia, because severe weather events in that state are not generally confined to

166 The IEEE standard is based on analysis of networks in the United States and Canada, and uses the natural logarithm to make the daily SAIDI normally distributed.

one day. This is a known quality in the IEEE standard, and is accepted in exchange for simplicity and ease of calculation.

4.5.2.1 Conclusion

On the basis of the information provided, it appears that use of the Box-Cox methodology proposed by ETSA Utilities, in place of the mechanism in the IEEE exclusion, may produce a more "normal" distribution of ETSA Utilities' historical performance data, making it better suited to the operation of the remaining elements of the IEEE exclusion. Subject to adequate verification of the supporting data in ETSA Utilities' regulatory proposal, the AER will consider applying the Box-Cox methodology to ETSA Utilities for the purposes of distributing data for the 2010-15 regulatory control period.

The AER is aware of the perceived limitations of the 2.5 beta method in treatment of weather driven events spanning multiple days, but considers this risk acceptable in the interests of simplicity and ease of calculation.

4.5.3 Issue capped incentive and uncapped targets

The AER is currently investigating ETSA Utilities' concern over the potential perverse incentives that occur when performance in a scheme year is such that the cap on revenue at risk is invoked, and its proposed solutions.

The issues raised in ETSA Utilities' submission point to a formulaic error in the STPIS, such that the s-factor calculation does not operate as intended in the scheme's design. This is not a matter that can be addressed in this framework and approach paper. Any alteration to the calculation of the s-factor in the STPIS will require an amendment to the scheme, and can only be made after consultation with all affected parties in accordance with the distribution consultation procedures in cl. 6.16 of the NER. The AER's likely approach is to apply the amended scheme to ETSA Utilities in the forthcoming regulatory control period. ETSA Utilities will be able to participate fully in consultation on amendments to the scheme.

Any amendments to the STPIS required to address this issue will be proposed and finalised before the submission of ETSA Utilities regulatory proposal in May 2009. This means that amendments to the scheme will not be finalised 19 months prior to the commencement of the regulatory control period as contemplated by cl. 1.8(b). Clause 1.8(b) was included in the STPIS so that DNSPs can have certainty as to the form in which the STPIS is likely to be applied to them in a forthcoming determination. Any amendment to the s-factor calculation is not expected to change the likely approach to the application of the STPIS outlined in this framework and approach paper, and will not hinder ETSA Utilities' ability to submit a fully compliant regulatory proposal to the AER. In these circumstances the AER considers the appropriate course is to proceed with consultation on the necessary amendments to the scheme, so that the issues identified can be rectified before the STPIS is applied to ETSA Utilities in the 2010-15 distribution determination. Taking all of this into account, the AER is of the view that the importance of addressing this error outweighs the issues of timing in cl. 1.8(b) of the scheme.

4.5.4 Consideration of the NER criteria

4.5.4.1 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

The STPIS is designed to generate benefits to consumers in the form of maintained or improved performance in the reliability of energy supply and in the level of customer service provided by DNSPs. The amount of any penalty or reward payable under the s-factor components of the STPIS is calculated with reference to the incentive rates in sections 3.3.2 and 5.3.2 of the scheme.

Incentive rates for reliability of supply parameters contained in the s-factor component of the STPIS were set on the basis of the latest and most robust economic study of Value of Customer Reliability (VCR)[167] available at the time the scheme was made, and estimate the value of service reliability as value per kilowatt hour of lost load for supply interruptions. The weightings assigned to each parameter are based on the importance of that measure to customers and end users.

The incentive rate for the telephone answering parameter that applies under the customer service component of the STPIS is based on the results of the 2002 customer willingness to pay survey undertaken in South Australia by KPMG[168] and subsequent analysis by Essential Services Commission of Victoria.

The potential penalties and rewards available to ETSA Utilities under the STPIS therefore reflect the benefit to consumers from the associated level of performance.

As noted above, VENCorp has commissioned a new VCR study, the results of which may supersede the values in the 2002 study applied in the AER's STPIS. [169] The AER will have regard to the results of this latest study in deciding how the STPIS will apply in the 2010-15 regulatory control period, and encourages ETSA Utilities and its customers and end users to consider whether incentive rates based on this new study would better reflect willingness to pay for improvements in service performance.

4.5.4.2 Any regulatory obligation or requirement to which ETSA Utilities is 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 STPIS does not currently include a quality of supply component, 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.

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[167] Charles River Associates, 2002, *Assessment of the Value of Consumer Reliability (VCR) – report prepared for VENCorp*; Essential Services Commission (Victoria), 2006, *Electricity Distribution Price Determination 2006-2010, Vol. 1*.

[168] These findings were also confirmed in a 2007 willingness to pay study undertaken by MacGregor Tan consultants in South Australia.

[169] CRA International, *Assessment of the Value of Customer Reliability (VCR)*, 12 August 2008.

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.

4.5.4.3 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 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, and 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.

As noted in section 4.5.2.1, on the basis of the historical performance data provided, it is possible that use of the Box-Cox methodology proposed by ETSA Utilities, in place of the mechanism in the IEEE exclusion that applies under the STPIS, may produce a more normal distribution of ETSA Utilities' daily SAIDI data, making it better suited to the operation of the remaining elements of the IEEE exclusion. Subject to adequate verification of the supporting data in ETSA Utilities' regulatory proposal, the AER will consider applying the Box-Cox methodology to ETSA Utilities for the purposes of distributing data for the 2010–15 regulatory control period if to do so would result in application of the exclusion in a way that better reflects past performance of ETSA Utilities' network.

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 consideration of the appropriate period of historical performance from which to determine performance targets and the application of exclusions for the forthcoming regulatory control period.

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

In its distribution determination for ETSA Utilities, the AER is also likely to apply an efficiency benefit sharing scheme (EBSS) and a demand management incentive scheme (DMIS). The likely approach to the application of these schemes is set out in chapters 5 and 6 of this framework and approach paper.

The EBSS creates incentives to realise operational efficiency gains. The STPIS serves to maintain or, where efficient, improve service levels (where customers are willing to pay for improved service) so that the incentive under the EBSS to minimise opex does not result in lower levels of service for customers.

The DMIS creates incentives to implement efficient non-network solutions. The STPIS is neutral regarding the level of reliability of network and non network solutions, neither encouraging nor discouraging non-network alternatives to augmentation. In this way it sends the same signal to maintain and improve reliability performance whether network or non-network solutions are adopted. The availability of the DMIS is expected to facilitate capacity building in demand management and investigation of viable non-network solutions, to address the concerns of some DNSPs that non-network alternatives pose risks to performance under the STPIS.

4.5.4.5 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 improvements in service. 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. The level of the revenue at risk cap determines the strength of the incentive provided to ETSA Utilities to maintain and improve performance. The extent of the financial penalty or reward must be sufficient to counter the incentive to reduce expenditure at the expense of service performance. The AER considers that ±3 per cent is sufficient to counter any incentive to reduce costs at the expense of service performance.

ETSA Utilities has submitted that a lower financial exposure of ±1 per cent is more appropriate, and will on the basis of its performance under the current ESCOSA SI scheme provide sufficient incentives. For the reasons outlined in section 4.5.1 above, the AER considers that a higher cap on revenue at risk is appropriate.

4.5.4.6 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 reflected in the incentive rates, as noted in section 4.5.4.1. Application of these incentive rates, which are based on the value customers place on improved service reliability, means that the amount of any penalty or reward received by ETSA Utilities will reflect customers' willingness to pay.

Again, the AER encourages ETSA Utilities and its customers and end users to consider whether incentive rates based on the new VCR study commissioned by VENCorp would better reflect willingness to pay for improvements in service performance.

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

There is a perceived disincentive to implement non-network alternatives to augmentation, such that incentives to undertake demand side management may be diminished in the absence of an adjustment to STPIS targets or an exclusion to recognise what is seen as a greater risk that targets will not be met. However, the AER considers it important that the STPIS remains neutral in its application to network and non-network measures. The risk associated with non network alternatives is better placed with a DNSP than with its customers. Where aspects of performance are within a DNSP's control, the associated risk should also lie with the DNSP.

4.6 AER's likely approach to the application of a STPIS

Having given full consideration to the matters identified in clause 6.6.2 of the NER, the AER's likely approach in the forthcoming distribution determination will be to apply the STPIS to ETSA Utilities. The STPIS will replace the current SI scheme, and will operate in conjunction with the average service standards and the GSL scheme administered by ESCOSA.

The AER will not apply the GSL component of the STPIS to ETSA Utilities in the forthcoming regulatory control period while the GSL scheme administered by ESCOSA remains in place. If at any time in the forthcoming regulatory control period ESCOSA ceases to apply a GSL scheme, the AER's likely approach is to apply the GSL component of the STPIS from the date the jurisdictional scheme is withdrawn.

The AER's likely approach is to apply the reliability of supply and customer service components of the STPIS to ETSA Utilities in the forthcoming regulatory control period, in the form of an s-factor. No quality of supply parameters are proposed for inclusion at this time, 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 the STPIS in future regulatory control periods.[170]

Table 4.5: STPIS – applicable parameters

Component/parameter	
Reliability of supply	
SAIDI	CBD feeders
	Urban feeders
	Short rural feeders
	Long rural feeders
SAIFI	CBD feeders
	Urban feeders
	Short rural feeders
	Long rural feeders
Customer service	
Telephone answering	All of network

[170] The AER intends to monitor ETSA Utilities' quality of supply performance as reported to ESCOSA. The AER will consider including quality of supply parameters in its STPIS in future regulatory control periods.

The AER does not consider the sampling method currently utilised in ETSA Utilities' reporting of MAIFI provides 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.

For each parameter that is applied, targets will reflect available data on past performance of ETSA Utilities' network, with adjustments as necessary under the STPIS. The incentive rates in sections 3.2.2 and 5.3.2 of the STPIS will apply to determine the amount of any revenue increment or decrement under the scheme, thereby ensuring that rewards or penalties under the STPIS are commensurate with the associated shift in performance, and reflect customer willingness to pay for improved delivery of services.

Within a total revenue at risk of ±3 per cent, the total revenue at risk against the customer service (telephone answering) parameter will be capped at ±0.5 per cent. Subject to this constraint, each (sub) parameter will be weighted in accordance with section 3.2.2 of the STPIS. The AER is not persuaded by ETSA Utilities' submission that the total revenue at risk under the STPIS should be capped at ±1 per cent, with a limit of ±0.05 per cent attached to the telephone answering parameter. The AER has had regard to ETSA Utilities' variable past performance against targets and average service standards, and 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. Within the greater scope of the STPIS relative to ESCOSA's SI scheme, the AER has concluded that a higher cap on revenue at risk is appropriate.

The AER has considered ETSA Utilities' submission that the IEEE exclusion, as reflected in the STPIS, is not suitable for application to ETSA Utilities. On the basis of the historical performance data provided this far, it is possible that use of the Box-Cox methodology proposed by ETSA Utilities, in place of the mechanism in the IEEE exclusion that applies under the STPIS, may produce a more normal distribution of ETSA Utilities' daily SAIDI data, making it better suited to the operation of the remaining elements of the IEEE exclusion. Subject to adequate verification of the supporting data in ETSA Utilities' regulatory proposal, the AER is likely to consider applying the Box-Cox methodology to ETSA Utilities for the purposes of distributing data for the 2010–15 regulatory control period if to do so would result in application of the exclusion in a way that better reflects past performance of ETSA Utilities' network.

The perceived limitations of the 2.5 beta method in treatment of weather driven events spanning multiple days have been recognised. However, the AER considers on balance that this is an acceptable risk in the interests of simplicity and ease of calculation.

The AER will continue to investigate ETSA Utilities' concern over the potential perverse incentives that occur when performance in a scheme year is such that the cap on revenue at risk is invoked, and its proposed solutions. Any amendments to the STPIS required to address this issue will be proposed and finalised before the submission of ETSA Utilities regulatory proposal in May 2009. An amendment to the s-factor calculation is not expected to change the likely approach to the application of the STPIS outlined in this framework and approach paper, and will not hinder ETSA Utilities' ability to submit a fully compliant regulatory proposal to the AER. For the reasons outlined above, the AER considers the appropriate course is to proceed with consultation on the necessary amendments to the scheme, so that the issues identified can be rectified before the STPIS is applied to ETSA Utilities in its 2010-15 regulatory control period.

5 Application of efficiency benefit sharing scheme

5.1 Introduction

This chapter sets out the AER's likely approach to the application of an efficiency benefit sharing scheme (EBSS) to ETSA Utilities in the forthcoming regulatory control period, and its reasons for that approach. Transitional issues associated with the operation of the existing efficiency carryover mechanism applicable to ETSA Utilities under the 2005-10 EDPD, which were considered in chapter 7 of the preliminary positions paper, are also considered in this chapter.

The EBSS provides for a fair sharing of operating expenditure (opex) efficiency gains and losses between DNSPs and their customers. The operation of the EBSS creates 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 must provide, in its distribution determination, details of how an EBSS will apply to the DNSP for the relevant regulatory control period.[171] The AER's framework and approach paper must set out its likely approach to the application of an EBSS to ETSA Utilities in its distribution determination for the 2010-15 regulatory control period.[172]

In implementing the EBSS, 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 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 desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses
- any incentives that DNSPs may have to capitalise expenditure
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.[173]

5.2.1 AER's distribution EBSS

The AER released its distribution EBSS on 26 June 2008. The EBSS is available on the AER's website, www.aer.gov.au.

[171] NER, cl. 6.3.2(a)(3)
[172] NER, cl. 6.8.1(b)(3)
[173] NER, cl 6.8.5(c)

The EBSS calculates revenue increments or decrements derived from the difference between a DNSP's outturn opex and its approved forecast opex. The EBSS is symmetrical, so that the DNSP retains the benefits of an efficiency gain (or bears 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 or loss was realised. 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.

The AER's EBSS provides for a nominal five year carryover period. This results in a benefit-sharing ratio of approximately 30:70 between a DNSP and its customers.[174]

5.2.2 Issues specific to South Australia: Statement of Regulatory Intent

On 23 March 2007, the Essential Services Commission of South Australia (ESCOSA) issued a statement of regulatory intent (SORI)[175] containing transitional arrangements relating to the efficiency carryover mechanism to which ETSA Utilities has been subject in the 2005-2010 regulatory period. 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]. [176]

The jurisdictional derogation for South Australia provides that the AER's application of an EBSS to ETSA Utilities for the forthcoming regulatory control period must be consistent with the SORI.[177]

The SORI does not limit the AER's discretion in formulating its own EBSS or in applying it to ETSA Utilities going forward. It is transitional in nature, and requires the AER to apply carryovers accumulated under the efficiency carryover mechanism put in place by ESCOSA for the current (2005-10) regulatory period as intended by ESCOSA.

Each annual carryover amount realised in the current regulatory control period will be calculated and used in calculating forecast opex and capex[178] in the AER's building block determination for ETSA Utilities' 2010-15 regulatory control period.

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174 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.

175 Clause 7.4 of the *Electricity Pricing Order* (EPO) allows ESCOSA to publish a statement of regulatory intent (SORI) which sets out how ESCOSA intends to exercise its powers under chapter 7 of the EPO.

176 *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

177 NER, cl. 9.29.5(c)

As noted above, the SORI requires the AER to carry any net negative efficiency amount calculated under the current period efficiency carryover mechanism as a negative (rather than a zero) amount. The AER has the discretion to either apply a negative carryover amount accumulated under the ESCOSA scheme in the current regulatory control period, or to defer it to offset any future positive carryover amount.

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

The AER's preliminary position was that the distribution EBSS would apply to ETSA Utilities in the forthcoming regulatory control period.

In chapter 7 of its preliminary positions paper, the AER stated that it would consider the desirability of deferring accumulated negative carryover amounts when the materiality of any such amount is known.[179]

5.4 Summary of submissions

ETSA Utilities provided the only submission in response to the AER's preliminary position on the application of the EBSS in its forthcoming distribution determination.

In its submission, ETSA Utilities acknowledges the application of the EBSS, as published by the AER on 26 June 2008, in determining operating expenditure efficiency from 1 July 2010. In addition, ETSA Utilities commits to provide, as part of its regulatory proposal:

- categories of uncontrollable operating expenditure that it submits should be excluded from the operation of the EBSS, and
- relevant growth adjustment methods that are applied to factor growth into its opex forecasts.

ETSA Utilities seeks clarification of a number of issues which it does not consider to be clearly defined, each relating to efficiency carryovers from the 2005-10 regulatory control period. These are discussed below.

5.4.1 Revealed cost year

In its submission, ETSA Utilities seeks clarification of the operation of the EBSS should year three of the current regulatory control period be used as the revealed cost year from which opex in the forthcoming regulatory control period is calculated, and in particular:

> …the calculation of current period operating expenditure efficiency gains/losses if the third year in the current control period, that is the year ending 30 June 2008, is used to build up [its] operating expenditure proposal

[178] Although the AER does not include capex in the operation of its EBSS, capex efficiencies realised in the current regulatory period under ESCOSA's efficiency carryover mechanism will be included in forecast capex allowances for ETSA Utilities in the forthcoming regulatory control period.

[179] AER Preliminary Positions Paper on the Framework and Approach for ETSA Utilities 2010-15, p. 87

> (ie year 3 rather than year 4 is the revealed cost or reference year). The reason one might seek to do use year 3 as the revealed cost or reference year in building up the operating expenditure proposal is that this will be the last year of audited regulatory accounts available at the time of lodging the regulatory proposal. [180]

ETSA Utilities considers that in this situation, the AER's EBSS would have operated to assume gains/losses in year four which would then be reversed in year five, the net effect being that there is neither an efficiency gain nor loss assumed in year four and five combined. ETSA Utilities assumes that the AER would make a similar adjustment to the ESCOSA efficiency carryover mechanism in determining the current period efficiency gain or loss with respect to year five of the regulatory control period. It submits that doing so would provide important consistency between the revealed cost year and the efficiency carryover mechanism, whilst not changing the ESCOSA efficiency carryover mechanism.[181]

5.4.2 Application of negative carryovers

ETSA Utilities submits that the AER's proposal to defer its decision on whether or not to defer negative carryovers until the amount of any such carryover is known does not constitute good regulatory practice. It considers that the scope of the SORI is such that the AER can defer negative carryovers to be offset by future positive gains.[182]

ETSA Utilities notes that neither the SORI nor ESCOSA's efficiency carryover mechanism have regard to the possibility that negative carryovers may arise as a function of external factors (and may not be management induced), or make adjustments for negative carryovers resulting from opex variations that are beyond its control. ETSA Utilities considers that this omission is sufficient basis for the AER to appropriately determine that, in the event that there is a net negative carryover, it should be deferred to offset any future positive carryover amount.[183]

5.5 Issues and AER's considerations

The AER notes ETSA Utilities' commitment to include proposed uncontrollable cost categories and details of any growth adjustments applied to factor growth into its opex forecasts in its regulatory proposal.

5.5.1 Revealed cost year

As a DNSP's building block determination for the following regulatory control period will be made before the end of the period during which the EBSS has applied, and therefore before actual opex in the final year of the regulatory control period (year five) is known, efficiency gains or losses in the final year of the regulatory control period are based on an estimate of actual opex in that year.[184] Under the AER's EBSS, this estimate is calculated as the forecast opex for year five minus the

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[180] ETSA Utilities: *Submission to the AER's Preliminary Positions Framework and Approach Paper for ETSA Utilities 2010-15*, p.27.
[181] ibid.
[182] ibid., p.30
[183] ibid., p.29
[184] While actual opex for the penultimate year of the regulatory control period (year four) will not be known at the time ETSA Utilities submits its regulatory proposal in May 2009, actual expenditure for year four will be know before the AER's distribution determination is made in April 2010.

difference between forecast and actual opex in the base year that forms the starting point from which forecast opex for the subsequent period is derived. The EBSS does not specify a particular year as the base year, but contemplates use of either year three or year four.

The efficiency carryover mechanism applied by ESCOSA during the current regulatory control period takes a different approach. To calculate final year efficiencies (at a time when actual expenditure in the final year of the period will not be known), actual expenditure in the last year of the regulatory period (year five) is assumed to be equal to expenditure in the previous year (year four), multiplied by the change in efficiency embodied in the original expenditure benchmarks between those years.

The use of year four as the revealed cost year essentially provides the same incentive properties under the EBSS and ESCOSA's efficiency carryover mechanism. While the incentive to make efficiency gains in the fourth year under the efficiency carryover mechanism will not be the same as all other years, ETSA Utilities will still have an incentive to reduce opex where feasible, which is the primary objective of the EBSS.

The final year regulatory adjustment in the AER's EBSS is designed to enable the EBSS to operate with forecast opex based on either year three or year four of the regulatory control period. However, the use of year three as the revealed cost year would, if ETSA Utilities had prior knowledge that year three could be adopted as the base year for opex forecasts for the forthcoming regulatory control period, skew the potential incentive properties provided in ESCOSA's efficiency carryover mechanism. In this case, ETSA Utilities would have an artificial incentive to build up year three costs (by either shifting opex from other years into year three, or simply spending more) to increase the potential forecasts for the 2010-15 regulatory control period.

The AER can not substitute the final regulatory year adjustment in its EBSS for that in ESCOSA's efficiency carryover mechanism. In its distribution determination for ETSA Utilities in the 2010-15 regulatory control period the AER must apply the calculation of final year efficiency gains under ESCOSA's efficiency mechanism, as intended by ESCOSA, in a manner consistent with the SORI.

5.5.2 Negative carryovers

While the SORI provides discretion to bank negative carryovers accumulated under ESCOSA's efficiency carryover mechanism to offset future positive amounts, the AER's EBSS does not contemplate the banking of negative carryovers. In the development of the EBSS, the AER considered that the potential to offset negative amounts against future positive amounts would dilute the incentives for DNSPs to continually reduce opex.[185] An accrued net negative carryover may incentivise DNSPs to artificially shift costs into the benchmark year to increase future opex

[185] For further explanation, see the AER's explanatory statement accompanying the proposed EBSS (April 2008) http://intranet.accc.gov.au/content/item.phtml?itemId=944549&nodeId=7c5e0d5c334e86281e55aa89dd116cd3&fn=Proposed%20EBSS%20explanatory%20statement%20%20(April%202008).pdf

forecasts. In addition, a banking mechanism becomes problematic when negative carryovers are accrued consistently in each year of the period.

The AER's EBSS does not include capex in its operation. There is therefore no potential for a positive capex carryover against which a net negative capex carryover from the current period could be offset, so that the discretion to defer a negative capex carryover is not available. The option of banking accumulated net negative carryovers is therefore only available for opex.

In its 2005-10 EDPD, ESCOSA provided a maximum allowance of $20.4 million in opex (in December 2004 dollars) over the five year period for ETSA Utilities to implement demand management initiatives. Any expenditure above this benchmark was to be at ETSA Utilities' cost, and any underspend was not to be treated as an efficiency gain for the purposes of the efficiency carryover mechanism (instead, it was to be returned to customers).[186] ESCOSA also decided to adjust the benchmark costs against which efficiency is assessed where there had been material changes to costs due to pass-through events (as permitted under the EPO), and where the amount of those costs had been approved by ESCOSA.[187]

The AER's EBSS also excludes opex spent on non-network alternatives (including opex spent on demand management and approved expenditure under the demand management innovation allowance discussed in chapter 6 of this paper) from the derivation of carryover amounts, and approved increases or decreases in actual opex associated with recognised pass through events.

However, the EBSS allows further adjustments (that the ESCOSA scheme does not) which seek to minimise the risk of negative carryovers resulting from opex variations over which the distributor has no control, by allowing DNSPs to propose cost categories which it considers to be uncontrollable for exclusion from the scheme. These categories must be proposed by ETSA Utilities in its regulatory proposal for consideration in the distribution determination. When making a decision whether or not to approve an uncontrollable cost category, the AER will have regard to whether the cost category is genuinely uncontrollable. ETSA Utilities will be required to maintain and provide disaggregated opex figures in support of any proposed uncontrollable opex categories to allow proper administration of the EBSS.[188]

In a situation where a negative carryover has been accrued under ESCOSA's efficiency carryover mechanism, but would not have been accrued under the AER's EBSS had it been in operation, the AER will consider allowing ETSA Utilities to bank negative carryovers to offset against future positive amounts.

In deciding whether to defer negative opex carryovers accrued in the 2005-10 regulatory control period, the AER will consider whether a net negative carryover:

[186] ESCOSA, *2005-2010 Electricity Distribution Price Determination, Part A: Statement of reasons*, April 2005, p. 100

[187] Ibid., p.70

[188] The AER notes that outturn opex for uncontrollable cost categories will not be assumed to be efficient for the purposes of forecasting costs for future regulatory control periods, so that the efficiency of base year costs for these categories will need to be established in ETSA Utilities' regulatory proposal.

1. was accrued, in whole or in part:

   a. in an opex category that is excluded by the EBSS but not by ESCOSA's efficiency carryover mechanism, or

   b. in an opex category that is an approved uncontrollable cost category under the AER's EBSS in ETSA Utilities distribution determination for the 2010-15 regulatory control period, and

2. is material in the sense that it is likely to have a significant and undesirable impact on the stability of prices.

5.5.3 Consideration of the NER criteria

In implementing the EBSS in its distribution determination for ETSA Utilities, the AER must have regard to a number of factors. These are discussed in turn below. Recognition of these factors in the design of the EBSS itself is discussed in more detail in the final decision on the EBSS, which is available on the AER's website (www.aer.gov.au).

5.5.3.1 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

The AER's EBSS assumes a five-year carryover period, which produces a sharing ratio of 30:70 between ETSA Utilities and its customers. This occurs over a five year period from the year the efficiency was realised, which may extend into the following regulatory control period where efficiencies are realised in year two or after.

Due to the symmetrical nature of the EBSS, ETSA Utilities will share the benefits of its efficiency gains with its customers and incur the costs of its efficiency losses, where these losses are deemed controllable. Customers will only incur higher prices as a result of the EBSS where efficiency losses are caused by factors beyond ETSA Utilities' control.

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.

5.5.3.2 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 AER's distribution EBSS does not extend to capital expenditure, and applies to operating expenditure only. Capex carryovers accumulated under ESCOSA's efficiency carryover mechanism will, however, be recognised in the approved capex forecasts in ETSA Utilities' distribution determination for the forthcoming regulatory control period.

The EBSS will operate to ensure that ETSA Utilities does not experience a material advantage in either deferring or advancing an efficiency gain or loss. For example, the measurement of gains and losses should not be artificially affected by shifting costs between years. Rather, it should represent genuine business outcomes that have arisen in the course of conducting the business in a prudent and diligent manner.

Under an incentive regulation framework, efficiencies are normally only retained until the end of the regulatory control period. Without an EBSS, ETSA Utilities may be incentivised 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 (five years) regardless of the regulatory year in which it is achieved, the EBSS reduces this incentive.

ETSA Utilities may also be incentivised to defer opex until year three and/or four of a regulatory control period (the two years from which a base year for future opex is likely to be chosen), to artificially increase opex forecasts for following regulatory periods. The incentive to increase opex for the regulatory period in potential base years is partly counterbalanced by the symmetrical nature of the AER's EBSS. The symmetrical nature of the EBSS means that any overspend in a particular year will be penalised for the full length of the carryover period, regardless of the year in which the overspend occurred. Any potential gains to ETSA Utilities from increasing opex in the base year will have to be weighed up against the penalties that will be incurred for five years after the overspend.

The EBSS does not assume that either year three or year four necessarily provides efficient outturn opex figures. In its regulatory proposal, ETSA Utilities will be required to provide supporting information as to the efficiency of costs in any base year proposed as the starting point for opex forecasts.

5.5.3.3 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 necessary to ensure continuity of incentives to improve efficiency. Without symmetrical carryovers, there is a perceived incentive to shift opex into the expected 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.

The deferral (or 'banking') of negative carryovers until they can be offset against future positive amounts dilutes the symmetry of the EBSS. Banking negative carryovers may further incentivise DNSPs to 'stack' opex in the benchmark year, resulting in artificially high opex forecasts for the subsequent period. While the AER will consider the merits of deferring any net negative opex carryovers accumulated under ESCOSA's efficiency carryover mechanism, as discussed in section 5.5.2 above, the AER's EBSS does not contemplate the banking of negative carryovers.

5.5.3.4 Any incentives that DNSPs may have to capitalise expenditure, and the possible effects of the EBSS on incentives for implementation of non network alternatives

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, a DNSP may have greater incentives to augment its network later in the period than to implement non-network alternatives that incur opex.

The proposed EBSS excludes all costs associated with non-network alternatives, including operating expenditure on demand management and expenditure under any demand management incentive scheme applied under the relevant distribution determination. This removes the potential impact of the EBSS on such decisions, which may otherwise discourage ETSA Utilities from considering demand side management.

5.6 AER's likely approach to the application of an EBSS

5.6.1 Implementation of the EBSS

Having given full consideration to the matters identified in clause 6.5.8(c) of the NER, the AER's likely approach in the forthcoming distribution determination is to apply the EBSS to ETSA Utilities. ETSA Utilities is required to propose any categories of uncontrollable opex it considers should be excluded from the operation of the EBSS as part of its regulatory proposal in May 2009. ETSA Utilities must also include in its regulatory proposal details of any growth adjustment methods it submits should be applied to factor growth into its opex forecast.

5.6.2 Transitional arrangements

In accordance with the SORI, the AER will recognise both capex and opex carryovers accumulated under the efficiency carryover mechanism administered by ESCOSA in the current regulatory period. Each annual carryover amount for the current regulatory period will be calculated and applied in the building block determination for the 2010-15 regulatory control period. Calculation of efficiency gains or losses in the final year (year five) of the current regulatory control period will be in accordance with ESCOSA's efficiency carryover mechanism.

The AER will incorporate both negative and positive carryover amounts accrued in any year of the current regulatory period into forecast opex amounts for the forthcoming regulatory period. 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 is, under the SORI, subject to the AER's discretion.

The exclusion of capex from the AER's EBSS means that the option of deferring a negative capex carryover amount accumulated under ESCOSA's efficiency carryover mechanism is not available.

The AER will exercise its discretion to defer a net negative opex carryover with regard to whether the accumulated negative carryover:

1. was accrued, in whole or in part:
   a. in an opex category that is excluded by the EBSS but not by ESCOSA's efficiency carryover mechanism, or
   b. in an opex category that is an approved uncontrollable cost category under the AER's EBSS in ETSA Utilities distribution determination for the 2010-15 regulatory control period; and
2. is material in the sense that it is likely to have a significant and undesirable impact on the stability of prices.

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 capex and opex objectives in chapter 6 of the NER require DNSPs to meet or manage the demand for standard control services. Demand management refers to measures undertaken by a DNSP to meet customer demand by shifting or reducing demand for standard control services rather than increasing supply.

The objective of the 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.[189] The DMIS operates in conjunction with existing incentives in the regulatory framework to pursue these objectives.

6.2 Requirements of the National Electricity Rules

The AER's distribution determination for ETSA Utilities for the 2010-15 regulatory control period must specify how a DMIS will be applied to ETSA Utilities in that period.[190] 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.[191]

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, and
- the willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme.[192]

[189] NER, cl. 6.6.3(a)
[190] NER, cl. 6.3.2(a)(3)
[191] NER, cl. 6.8.1(b)(4)
[192] NER, cl. 6.6.3(b)

6.2.1 DMIS applicable to ETSA Utilities

On 17 October 2008, after consultation under the NER, the AER published a DMIS to be applied to Energex, Ergon Energy, and ETSA Utilities in the regulatory control periods commencing 1 July 2010. The DMIS is available on the AER's website (www.aer.gov.au).

The DMIS is in two parts:

Part A – demand management innovation allowance

The demand management innovation allowance (DMIA) allows the recovery of costs for demand management projects and programs throughout the regulatory control period, subject to satisfaction of defined criteria. The DMIA is provided as a capped, annual ex ante allowance, and subject to a single adjustment in the subsequent regulatory control period to return any expenditure not approved, or any amount of the DMIA that is not spent, to customers.[193]

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

Part B – recovery of forgone revenue

Part B of the DMIS allows recovery of revenue forgone by a DNSP within the relevant regulatory control period as a result of a reduction in the quantity of electricity sold due to the implementation of non-tariff demand management projects and programs approved under the DMIA. Part B will only apply to a DNSP where the form of control that applies to its standard control services results in its approved regulated revenue for those services being dependent on the quantity of energy actually sold.

Recovery of forgone revenue is in addition to the capped amount of the DMIA, however the actual amount that can be recovered is limited to approved revenue forgone resulting from a successful project established under part A of the scheme. The forgone revenue will be provided in the subsequent regulatory control period, at the same time as the single adjustment under part A of the scheme.

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

The preliminary position on the application of a DMIS to ETSA Utilities was based on the proposed DMIS developed for Queensland and South Australia, which was published on the 30 June 2008 at the same time as the preliminary positions paper. That scheme included the ex ante demand management innovation allowance in part A of the final scheme, but not the forgone revenue component in part B.

[193] The AER considers that capex payments made under the DMIA could be treated as capital contributions under clause 6.21.2 and therefore not rolled into the RAB at the start of the next regulatory control period, however the AER's decision in that regard will only be made as part of the next revenue determination.

The AER's preliminary position was that it was likely to apply a DMIS in the form of an ex ante DMIA to ETSA Utilities for the 2010-15 regulatory control period. The DMIA was to be capped at a total of $3 million over the regulatory control period, nominally allocated in five equal annual instalments of $600 000. The DMIA was to be provided in addition to any opex and capex allowances for demand management projects included within the distribution determination for ETSA Utilities.

6.4 Summary of submissions

ETSA Utilities and the Total Environment Centre (TEC) made submissions on the likely approach to the application of the DMIS to ETSA Utilities in the 2010-15 regulatory control period.

6.4.1 Amount of the DMIA

While it supports the development and application of an innovation allowance for ETSA Utilities, the TEC submits that the amount given under the DMIA is too low to promote extensive demand management projects and should be greatly increased. The TEC stated that the amount of $3 million ($600 000 per year) for ETSA Utilities for the entire regulatory control period under the DMIA was a minute sum in relation to ETSA Utilities' overall spending and annual expenditure,[194] and recommended that the DMIA be set at five per cent of the projected network capital expenditure.[195]

ETSA Utilities did not comment specifically on the appropriate amount of the DMIA, submitting instead that an uncapped mechanism in the nature of the New South Wales D-factor should be applied (see discussion below).

6.4.2 Application of a D-factor to South Australia

ETSA Utilities submits that the DMIA, in the absence of any other incentive schemes, will be insufficient to encourage it to materially pursue further demand management opportunities in the next regulatory control period.

ETSA Utilities considers the deferral of capital expenditure is insufficient to encourage DNSPs to implement demand management options rather than network solutions, because:

- demand management solutions remain largely unproven and therefore reflect a higher risk than network-based solutions
- there are strong penalties under service incentive schemes, and a severe community backlash can occur, if a demand management solution fails to deliver the required demand reduction under peak demand conditions
- the benefit of deferral is limited to the return on and of the capital expenditure and this return is substantially reduced near the end of the regulatory period

194 The Total Environment Centre, *Demand Management Incentives for Energex, Ergon Energy and ETSA Utilities for 2010-15*, submission to the AER, p. 7-8.
195 ibid, p. 2.

- the DNSP does not have access to benefits accruing to other industry sectors such as transmission companies, generators and retailers.[196]

ETSA Utilities also notes that under a weighted average price cap (WAPC) form of control, a reduction in sales will result in a reduction in revenue. It therefore submits that any reduction in sales must be taken into account in the financial assessment of a demand management option.[197]

To address these issues, ETSA Utilities proposed that a D-factor scheme be incorporated into its DMIS, but that it differ from the D-factor applied in New South Wales to take into account:

1. the encouragement of broad based demand management; and
2. potential government policy change in respect to demand management over the next regulatory period.[198]

6.5 Issues and AER's considerations

The Final DMIS for DNSPs in Queensland and South Australia, published by the AER on 17 October 2008 and described in section 6.2.1 above, is largely consistent with the Proposed DMIS released in June. The key differences are:

- refinements to the approval criteria and reporting requirements under the DMIA component of the scheme (part A), and
- the incorporation of a forgone revenue mechanism (part B of the DMIS) similar to that already included in the AER's DMIS for DNSPs in New South Wales and the Australian Capital Territory in their 2009–14 regulatory control periods, which was not included in the proposed DMIS.

6.5.1 Amount of the DMIA

The DMIA is not intended to be the only source of cost recovery for demand management expenditure. Rather, it is appropriate that a DNSP recover demand management costs primarily through forecast opex and capex approved at the time of the distribution determination, so that recovery through regulated revenues of amounts in excess of that contemplated by the DMIA is subject to the more rigorous, ex-ante assessment of forecast opex and capex required by the NER.

The DMIA is designed to supplement a DNSP's approved capex and opex, to facilitate investigation and implementation of demand management strategies. Where they prove viable, this will allow DNSPs to implement non-network alternatives where efficient, and to manage the expected demand for standard control services through means other than expansion of supply.

[196] ETSA Utilities, *Submission to AER's preliminary positions, framework and approach ETSA Utilities 2010–15*, pp. 32-33.
[197] ibid, p. 33.
[198] ibid, p. 33.

Larger, on-going demand management programs and projects should be able to be foreseen at the time of the determination, and as such should be included in forecast opex and capex within DNSPs' regulatory proposals.

Application of the TEC's proposed allowance of five per cent of forecast capex would, in the current regulatory period, have afforded ETSA Utilities an allowance of \$37.65 million (real 2004 dollars).[199] The latest demand management progress report published by the Essential Services Commission of South Australia (ESCOSA) indicates that by December 2008 ETSA Utilities expects to have spent only \$10.2 million[200] of the lower allowance of \$20.4 million (approximately 2.7 per cent of approved forecast capex) for demand management trials approved by ESCOSA in the 2005-10 Electricity Distribution Price Determination (EDPD). This is despite its initial request for a higher (\$25 million) allowance,[201] and significant preparatory work undertaken in cooperation with ESCOSA at the time of the EDPD. While the EDPD requires, and the AER will, claw back the amount of any underspend against the \$20.4 million allowance at the end of the current regulatory period and return it to customers, the AER does not consider that allowances of such magnitude are appropriately provided outside the opex and capex approval processes in clauses 6.5.6 and 6.5.7 of the NER.

The modest, use-it-or-lose it nature of the DMIA is appropriate given its broad scope and focus on innovation, research and development. When regard is had to the long-term nature of expected benefits to consumers from the scheme, and the limited information available on customer willingness to pay for increases in costs resulting from the implementation of a DMIS, the AER is not satisfied that an increase to the DMIA is appropriate at this time. An allowance of a greater amount would require a corresponding increase in prescription in the scheme's application, which would impose constraints on the use of the DMIA that are contrary to the scheme's objectives.

The likely approach is therefore to apply a DMIA in the amount of \$3 million (\$600 000 per annum) to ETSA Utilities in the forthcoming regulatory control period. 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.

6.5.2 Application of a D-factor to South Australia

As explained in chapter 3 of this framework and approach paper, the form of control applied to ETSA Utilities' standard control services in the forthcoming regulatory control period will be a WAPC. ETSA Utilities has noted that, under this form of control, a reduction in the quantity of electricity sold will lead to a reduction in revenue. However, the AER does not agree that the best solution to this and the other issues that ETSA Utilities has raised is the extension of the D-factor applied in New South Wales to South Australia.

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199 ETSA Utilities' approved forecast capex in the 2005-2010 regulatory period is \$753 million (\$real Dec 2004), Essential Services Commission of South Australia, *2005-2010 Electricity Distribution Price Determination, Part A: Statement of Reasons,* April 2005, p. 91.

200 ESCOSA, *ETSA Utilities Demand Management Program –Progress Report*, October 2008, p. 34

201 ETSA Utilities, Expenditure Submission 2005/06 – 2009/10, p. 11.

Although the potential for a D-factor scheme to provide positive incentives for a DNSP to conduct demand management initiatives has been recognised, it has also been noted that the results of the D-factor in New South Wales have to date been inconclusive. The AER's preference is therefore to continue its observation of that scheme in the 2009–14 New South Wales regulatory control period, to build a better foundation from which to consider its effectiveness and potential for broader application. Rather than extend that approach to other jurisdictions, this has led the AER to develop an alternative scheme that approaches the objectives set out in chapter 6 of the NER at a more holistic level.

Clause 6.6.3 of the NER allows the AER to develop and implement a DMIS that provides incentives for DNSPs not only to implement efficient non-network alternatives, but also to manage the demand for standard control services in other ways. The D-factor applied in New South Wales only allows DNSPs to recover the costs of demand management initiatives where they can be shown to be cost effective in addressing specific network constraints. The DMIS developed for application in Queensland and South Australia is broader in its operation, and provides for recovery of both broad-based and peak demand management projects (and if part B applies, the forgone revenue resulting from these projects) throughout the regulatory control period. The extension of the scheme to cover broad-based demand management is consistent with the second objective of the DMIS contemplated by chapter 6, and with the first of ETSA Utilities' proposed amendments to the New South Wales D-factor.

The DMIA aims to provide incentives for ETSA Utilities to conduct research and investigation into innovative techniques for managing demand. Unlike DNSPs to which the D-factor applies, ETSA Utilities will not be required to demonstrate a reduction in demand, or the deferral of a planned capex project, for cost recovery: cost recovery under the DMIA is not dependent on the success of the demand management initiative. This is in keeping with the DMIA's focus on improved demand management capability and capacity, and promotion of innovative and new developments in the area of demand management. In this way, the DMIS will encourage greater consideration of non-network alternatives to augmentation in the decision making processes of DNSPs, so that in the future demand management projects may increasingly be identified as viable alternatives to network augmentation as part of the DNSP's capex and opex proposals. This feature of the DMIA is designed to break down the barriers to implementation of demand management solutions arising from DNSP's claims that such options remain largely unproven and reflect a higher risk than network-based solutions in the context of service incentive schemes and community expectations.

In its submission, ETSA Utilities has questioned the adequacy of the incentives within the chapter 6 framework to drive demand management, noting that the benefit of capex deferral is limited to the return on and of the capital expenditure, and is substantially reduced near the end of the regulatory control period. It also suggests that DNSPs do not have access to benefits accruing to other industry sectors such as transmission companies, generators and retailers.

As ETSA Utilities itself has noted, the benefit to it from demand management lies in not having to invest as much in building, managing and maintaining an unnecessarily enlarged network[202]:

> "It is true that the simplest way [to meet increased demand] is indeed to keep building infrastructure to support the continual increase in peak demand for more electricity by South Australians (a demand mainly driven by air conditioners).
>
> ETSA Utilities believes that, as the current infrastructure is only used to capacity for a very few days each year, it makes no business sense, to keep building infrastructure to satisfy this very short-term high demand each summer.
>
> After all, would any family build an extra room on to their home just for friends who come to stay once a year?[203]

In addition to the implementation of a DMIS, the criteria for approval of forecast opex and capex in a distribution determination under clauses 6.5.6 and 6.5.7 of the NER have been designed to reflect the expectations of policy makers that regulatory proposals submitted by DNSPs will, as intended, demonstrate proper consideration of efficient non-network alternatives and demand management strategies. Before it can approve ETSA Utilities' forecasts of opex and capex for the forthcoming regulatory control period, the AER must be satisfied that those forecasts reasonably reflect the costs of meeting the objective of not only meeting but managing demand for standard control services. In so satisfying itself, the AER must have regard to the extent to which ETSA Utilities has considered, and made provision for, efficient non-network alternatives. ETSA Utilities must therefore demonstrate to the AER's satisfaction that its proposed forecasts reflect these objectives and factors.

The AER has taken into account the impact of the new WAPC form of control on ETSA Utilities' incentives to adopt or implement efficient non-network alternatives, vis-a-vis its current form of control. In recognition of the reduction in revenues that will result from a reduction in the quantity of electricity sold, and the associated disincentives to implement demand management, the AER has included in part B of the DMIS a forgone revenue mechanism modelled loosely on that in the New South Wales D-factor. Part B of the DMIS will allow ETSA Utilities to recover any revenue forgone as a result of the implementation of demand management projects or programs approved under the DMIA in part A of the scheme, within the regulatory control period in which the scheme has applied. At the time of its next regulatory proposal in 2014, ETSA Utilities will be able to adjust its demand and expenditure forecasts to reflect the ongoing impact and continued application of such projects and programs. This mirrors the operation of both the D-factor and innovation allowance applied in New South Wales, each of which allow recovery of forgone revenue attributable to their operation within the regulatory control period in which they have applied.

The AER's likely approach is to apply the forgone revenue mechanism in part B of the DMIS to ETSA Utilities in the forthcoming regulatory control period, to remove

[202] http://www.etsautilities.com.au/default.jsp?xcid=992#Whobenefits

[203] http://www.etsautilities.com.au/default.jsp?xcid=992#Whyusedemandmanagementtodealwiththisandnotsimplybuildmorepowerinfrastructuretomeetincreaseddemand

any disincentive ETSA Utilities may have under a WAPC to make proper use of the DMIA in that period.

6.5.3 Consideration of NER criteria

6.5.3.1 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 DMIS encourages the implementation of demand management initiatives which provide long term efficiency gains to energy users that are expected to outweigh any short term price increases. The allowance is designed to provide incentives for 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 DMIS 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 DMIS is a modest scheme, provided on a use-it-or-lose-it basis. Consequently increases in customer prices are expected to be minimal. The DMIA in part A of the DMIS will be capped at a total of $3 million over the regulatory control period, nominally allocated in five equal, annual instalments of $600 000. This allowance will enable 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 application of the forgone revenue component in part B of the DMIS to ETSA Utilities is intended to remove any disincentive to make full and effective use of the DMIA under a WAPC form of control. In effect, it will mirror regulated revenue that would have otherwise have been earned within the regulatory control period, but for the implementation of the relevant demand management project or program. In this sense the effective reward is commensurate to the benefits to consumers from the effective operation of the scheme.

6.5.3.2 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

In applying the DMIS, the AER has had regard to the effects that particular control mechanisms may have on the incentives or disincentives for DNSPs to undertake demand management. The AER accepts that incentives for demand management may be affected by the control mechanism applied to a DNSP's standard control services. Under forms of control where revenue is at least partially dependent on the quantity of electricity sold (e.g. a price cap), a successful demand management program that causes a reduction in demand may result in less revenue to a DNSP.

The AER has determined that ETSA Utilities will be subject to a WAPC, which may result in its revenue being at least partially dependent on the amount of electricity sold, creating disincentives for ETSA Utilities to undertake demand management initiatives. To remove this disincentive, the AER's likely approach is to apply part B of the DMIS to ETSA Utilities. Within the forthcoming regulatory period this will allow it to recover any forgone revenue directly attributable to a reduction in the quantity of electricity sold due to the implementation of a non-tariff demand management program approved under the DMIA in part A of the DMIS. Application of part B of the scheme is intended to remove any disincentive to make full and effective use of the DMIA that may otherwise occur under a WAPC.

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

In applying a 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 of supplying electricity in times of peak demand.

There is scope within the current regulatory arrangements for ETSA Utilities to provide efficient pricing structures, for instance in the application of peak tariffs or time-of-use tariffs to ETSA Utilities' 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 that, in making its distribution determination for, or approving a pricing proposal from, ETSA Utilities for the purposes of the NER, the AER 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.[204]

The AER considers that efficient pricing structures can assist the effectiveness of demand management programs, and that the availability of a DMIA will provide capacity for ETSA Utilities to conduct tariff-based demand management programs which will provide further information on mechanisms for efficient pricing.

6.5.3.4 The possible interaction between a DMIS and other incentive schemes

In applying a DMIS to ETSA Utilities the AER must have regard to the interaction of that scheme with other incentive schemes. As outlined in chapters four and five of this paper, the AER's likely approach is to apply both an EBSS and a STPIS to ETSA Utilities in the 2010-15 regulatory control period.

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

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 EBSS excludes all costs associated with non-network alternatives, including opex spent on demand management and expenditure under the DMIS, from the calculation of opex overspends and underspends. This removes the potential impact of the EBSS on a decision to implement demand management or non-network alternatives, which may otherwise discourage ETSA Utilities from doing so.

The AER is aware of the perceived disincentive to implement non-network alternatives to augmentation created by the reliability performance measures in its STPIS, such that incentives to undertake demand side management may be diminished by what is seen as a greater risk that targets will not be met. As discussed in section 6.5.2, the DMIS is designed to facilitate improved demand management capability and capacity, and to promote innovative and new developments in the area of demand management so that demand management projects may increasingly be identified as viable alternatives to network augmentation. This feature of the DMIA is designed to break down the barriers to implementation of demand management solutions arising from DNSP’s claims that such options remain largely unproven and reflect a higher risk than network-based solutions in the context of service incentive schemes and community expectations.

The application of the DMIS 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.

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

In considering its likely approach to the application of a DMIS to ETSA Utilities, the AER has had regard to the extent to which South Australian customers and end users are willing to pay for increases on costs resulting from the implementation of the scheme.

The AER considers that application of a modest, low cost and administratively streamlined scheme such as the DMIS developed for ETSA Utilities, under which the cost increases experienced by customers and end users will be minimal, is appropriate at this time. Implementation of the scheme will allow ETSA Utilities to investigate and undertake demand management initiatives which will provide long term benefits to consumers that will outweigh the short-term costs of implementing the scheme.

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

Having had regard to submissions in response to the preliminary positions paper and the requirements of the NER, the AER’s likely approach is to apply both part A and part B of the DMIS to ETSA Utilities in the 2010-15 regulatory control period.

The DMIA will be capped at a total of $3 million over the regulatory control period, nominally allocated in five equal instalments of $600 000. 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.

ETSA Utilities will be subject to a WAPC, which may result in its recovery of the annual revenue requirement being at least partially dependent on the amount of electricity sold, creating potential disincentives for ETSA Utilities to undertake demand management initiatives. To counter this disincentive, the AER's likely approach is to apply part B of the DMIS to ETSA Utilities, to allow it to recover any forgone revenue directly attributable to a reduction in the quantity of electricity sold due to the implementation of a non-tariff demand management program approved under the DMIA.

The DMIS complements the incentive properties that are expected to flow from the application of the STPIS and EBSS within the broader incentive framework set out in chapter 6 of the NER. The AER is satisfied that the combination of the capped DMIA and the forgone revenue component of the DMIS will provide appropriate incentives to ETSA Utilities to adopt or implement efficient non-network alternatives under a WAPC, without providing a reward that outweighs the benefits to consumers likely to result from the scheme or the willingness of customers and end users to pay for its implementation.

7 Other matters - transition from pre-tax to post-tax

7.1 Introduction

Chapter 6 of the National Electricity Rules (NER) requires that DNSPs be regulated using a post-tax revenue model (PTRM). 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 information requirements relating to the application of a post-tax approach will be included as a part of a Regulatory Information Notice (RIN) detailing the information that ETSA Utilities must provide in its regulatory proposal on 31 May 2009.

7.2 Requirements of the National Electricity Rules

The jurisdictional derogation for South Australia in chapter 9, Part D of the NER requires the AER's distribution determination for ETSA Utilities for the regulatory control period commencing on 1 July 2010 to 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.[205]

For clarity, nothing in this paper should be construed as an agreement between the AER and ETSA Utilities for the purposes of the derogation.

Chapter 9, Part D of the NER also requires the AER to determine the amount ETSA Utilities may receive by way of capital contributions, prepayment and/or financial guarantee in respect of a South Australian network.[206]

7.3 AER's preliminary positions - elements of the post-tax revenue model

7.3.1 Estimation of the initial tax asset base

The AER noted in its preliminary positions paper that it would work with ETSA Utilities to ensure that the tax asset values adopted at the commencement of the next regulatory control period and applied in the post-tax revenue model are reasonable and appropriately substantiated.[207]

[205] NER, cl. 9.29.5(b)(1)
[206] NER, cl. 9.29.6
[207] AER, *Framework and Approach Paper – ETSA Utilities 2010-15*, Preliminary Positions, June 2008, p. 100.

7.3.2 Depreciation

In its preliminary positions paper, the AER noted that where the PTRM calculates forecast depreciation (return of capital) using a particular method (e.g. straight-line), cl. S6.2.3(c)(2) of the NER provides that the roll-forward model (RFM) must use the same depreciation method.[208]

While identifying straight-line depreciation as an approach compliant with the NER, the AER noted that it would assess depreciation schedules proposed by ETSA Utilities (for both tax and economic depreciation) against the requirements of the NER in making its distribution determination.

7.3.3 Capital contributions in the current and previous regulatory control period

The preliminary position was that capital 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 regulatory asset base (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.[209]

7.3.4 Capital contributions during the forthcoming control period

For the purposes of consistency with the previous regime, the preliminary position was 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.[210] This approach would involve ETSA Utilities providing a forecast of capital contributions from customers over the regulatory control period. These contributions would be included in the estimation of the tax building block, but excluded from the RAB. The AER would determine whether the forecasts are reasonable with regard to clauses 6.21.2 and 9.29.6 of the NER.

7.3.5 Timing assumptions

The preliminary position was 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.[211]

7.3.6 Carried-forward tax losses

The preliminary positions paper noted that 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

[208] ibid., p. 101.
[209] ibid.
[210] ibid.
[211] ibid., p. 102.

a profit before income tax of $142.3m, and a net profit of $136.9m.[212] The AER therefore proposed that tax losses be set to zero in the PTRM.[213]

7.3.7 Other issues

ETSA Utilities' regulatory proposal must incorporate its proposed transitional arrangements to take into account the change from a pre-tax to a post-tax revenue model. If an agreement between the AER and ETSA Utilities on these arrangements is reached, the proposed arrangements must be consistent with that agreement.

The preliminary positions paper noted that, in order to estimate a tax building block, the AER will ensure that in ETSA Utilities' regulatory proposal:

- 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.[214]

7.4 Summary of submissions

ETSA Utilities was the only party to make a submission on the approach to the transition from pre-tax to post-tax regulation.

ETSA Utilities' submission focussed on the following elements of the preliminary position paper.

7.4.1 Estimation of the initial tax asset base

ETSA Utilities accepts in principle a working methodology for estimation of the initial tax asset base that is prima facie consistent with the Ernst and Young advice on transitioning electricity distribution businesses from pre-tax to post-tax regulation commissioned by the AER in November 2006, and the methodology currently being used to affect this transition for DNSPs in NSW and the ACT.[215]

7.4.2 Depreciation

ETSA Utilities does not consider that there is a requirement for the method of depreciation chosen for tax depreciation to be consistent with the method applied in the depreciation of the RAB. ETSA Utilities considers it well recognised that there will be differences in other aspects of depreciation of the RAB and the regulated tax base (for example - tax versus regulatory asset lives).[216]

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[212] ibid., p. 102.
[213] ibid.
[214] ibid.
[215] ibid. For Ernst and Young advice see also AER, *Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009-2014*, Preliminary positions, November 2007, p. 58.
[216] ibid.

7.4.3 Other issues – work in progress

ETSA Utilities submits that work-in-progress at 30 June 2010 should be included and depreciated for tax purposes as a one-off transitional issue.[217]

7.5 Issues and AER's considerations

While the jurisdictional derogation for South Australia allows the AER and ETSA Utilities to agree upon arrangements necessary to deal with the transition to a post-tax revenue model, no agreement has been reached at this time. In the event that an agreement cannot be reached before ETSA Utilities is required under the NER to submit its regulatory proposal, the AER will (through a regulatory information notice) require ETSA Utilities to include in its proposal sufficient information to effect the transition from pre-tax to post-tax regulation. The transitional arrangements in ETSA Utilities' regulatory proposal will then be assessed on their merits against the requirements of the NER, with regard to any submissions received.

The remaining sections of this chapter provide guidance on what the AER is likely to consider in satisfaction of the requirements of the NER, in relation to the issues raised in ETSA Utilities' submission.

7.5.1 Estimation of the initial tax asset base

The positions taken in the preliminary positions paper, the guidelines for the national distribution PTRM, and where applicable under chapter 6[218] the guidelines, models and schemes developed by the AER for NSW and the ACT, are likely to be taken into account in the AER's consideration of the initial tax asset base in its distribution determination for ETSA Utilities. To the extent practicable, the AER will seek to ensure consistency in the arrangements for the transition from pre-tax to post-tax regulation between affected DNSPs.

7.5.2 Depreciation

ETSA Utilities submits that tax depreciation may be different from economic depreciation. For example, straight-line depreciation may be used to estimate depreciation for the RAB, while reducing balance depreciation may be used to estimate tax depreciation and the estimated tax building block.

Applying different depreciation methods to the tax asset value and the RAB may increase the complexity of the PTRM without making a material difference to the estimated tax expense. However, there is no requirement in the NER that the depreciation method applied to the RAB be consistent with the method used to estimate tax depreciation, provided that the values used for the RAB and tax asset value are consistently recorded in both the PTRM and the RFM. The guidelines for the PTRM (in the handbook) allow changes to the depreciation method for either depreciation on the RAB or tax asset base.

When considering the issue of depreciation (for both the tax building block and the RAB) the AER will have regard to the NER requirements relating to depreciation, the

217 ibid., p. 37.

218 As distinct from the transitional rules governing the AER's distribution determinations for DNSPs in NSW and the ACT.

PTRM and the RFM. Depreciation for the RAB must be calculated using depreciation schedules which conform to the following requirements:

- the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets[219]
- the sum of the real value of the depreciation that is attributable to any asset or category of assets over the economic life of that asset or category of assets must be equivalent to the value at which that asset or category of assets was first included in the RAB[220], and
- the economic life of the relevant assets and the depreciation methods and rates underpinning the calculation of depreciation for a given regulatory control period must be consistent with those determined for the same assets on a prospective basis[221].

For the purposes of estimating the cost of corporate income tax the NER require that the estimate must take into account the estimated depreciation for the regulatory year for tax purposes, for a benchmark efficient DNSP, of assets included in the RAB.[222]

ETSA Utilities' regulatory proposal must be consistent with the above requirements.

7.5.3 Other issues – work in progress

Capital expenditure programs that have not been fully completed as at the beginning of the forthcoming regulatory control period (work in progress) should be included in estimating the initial tax asset value in the PTRM submitted as part of ETSA Utilities' regulatory proposal. As the PTRM recognises capital expenditure on an as-incurred basis, work-in-progress will be a one-off transitional issue.

7.6 AER's likely approach to the transition from pre-tax to post-tax

The NER are clear in requiring the AER, in its first distribution determination for ETSA Utilities, to include appropriate transitional arrangements to take into account the transition from a pre-tax to a post-tax revenue model. While the jurisdictional derogation for South Australia allows the AER and ETSA Utilities to agree upon transitional arrangements, no agreement has been reached between the parties at this time. Nothing in this framework and approach paper should be construed as an agreement between ETSA Utilities and the AER under cl. 9.29.5(b) of the NER.

In the absence of any such agreement, arrangements for the transition from pre-tax to post-tax regulation will be considered in accordance with the requirements of the NER at the time of its distribution determination for ETSA Utilities. The AER will (through a regulatory information notice) require ETSA Utilities to include in its proposal sufficient information to effect the transition from pre-tax to post-tax regulation. The transitional arrangements in ETSA Utilities' regulatory proposal will

[219] NER, cl. 6.5.5(b)(1)
[220] NER, cl. 6.5.5(b)(2)
[221] NER, cl. 6.5.5(b)(3)
[222] NER, cl. 6.5.3(2)

then be assessed on their merits under the NER, with regard to any submissions received.

The information requirements relating to this transition will be set out in the regulatory information notice served on ETSA Utilities under the NEL, at the same time that details of the information ETSA Utilities must provide in and with its regulatory proposal are provided. This approach is similar to that taken in the transition process for DNSPs in New South Wales and the Australian Capital Territory. The positions taken in the preliminary positions paper, the guidelines for the national distribution PTRM, and where applicable under chapter 6[223] the guidelines, models and schemes developed by the AER for NSW and the ACT, are likely to be taken into account in the AER's consideration of transitional arrangements in its distribution determination for ETSA Utilities. To the extent practicable, the AER will seek to ensure consistency in the arrangements for the transition from pre-tax to post-tax regulation between affected DNSPs.

223 As distinct from the transitional rules governing the AER's distribution determinations for DNSPs in NSW and the ACT.

Appendix A: Classification of ETSA Utilities' distribution services in the current regulatory control period

This appendix sets out ETSA Utilities' service classifications for the 2005-10 regulatory control period. These classifications are reproduced from the 2005-10 Electricity Distribution Price Determination (EDPD)[224], 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:

a. 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;

b. 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.

Excluded Services Schedule

1.1 Public Lighting

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

(a) Public lighting services including:

  (i) operation and maintenance of public lighting; and

  (ii) provision of public lighting assets.

1.2 New and Upgraded Connection Points

(a) The:

  (i) provision of a new *connection point*, including associated extension or augmentation of the *distribution network*; or

  (ii) 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*.

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

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

1.3 Service Standards

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

  (i) 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

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

1.4 Stand-By and Temporary Supply

(a) The following services associated with stand-by and temporary supply:

  (i) provision of electric plant for the specific purpose of enabling the provision of top-up or stand-by supplies or sales of electricity;

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

  (iii) provision of temporary supplies; and

  (iv) provision of reserve (duplicate) supply.

1.5 Distribution System

(a) 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*.

1.6 Metering Services

(a) In relation to *small distribution network users*, the provision of *metering services*:

(i) 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*;

(ii) 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 installation type 7* containing a *meter* of the type that *ETSA Utilities* would ordinarily install.

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

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

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

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

1.7 Electricity Distribution and Electricity Metering Codes

(a) The following services provided in connection with the *Electricity Distribution Code* and the *Electricity Metering Code:*

(i) application for an account or new supply;

(ii) provision of a copy of the *Electricity Distribution Code* or the *Electricity Metering Code*;

(iii) provision of old billing data;

(iv) *meter* testing at the request of a *distribution network user*;

(v) after-hours reconnection;

(vi) reconnection due to a *distribution network users'* fault; and

(vii) disconnection services provided to a *retailer*, or a *distribution network user*.

1.8 Embedded Generation

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

1.9 Retailer of Last Resort

(a) 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.

1.10 Other Services

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

(b) investigation and testing services;

(c) asset location and identification services;

(d) the transportation of electricity not consumed in the *distribution system*;

(e) the transportation of electricity to *distribution network users* connected to the *distribution system* adjacent to the *transmission system*;

(f) repair of equipment damaged by a *distribution network user* or a third party;

(g) provision of

(i) high *load* escorts;

(ii) measurement devices;

(iii) protection systems;

(iv) pole attachments;

(v) ducts and conduits; and

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

Definitions

Connection services means either or both of the:

a. 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*;

b. 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:

a. 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*;

b. the management, maintenance and operation of the *distribution network* to provide the *network capability* referred to in paragraph (a) of this definition; and

c. 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*.

Appendix B: AER's likely approach to classification of ETSA Utilities' distribution services in the forthcoming regulatory control period

This appendix sets out the AER's likely approach to ETSA Utilities' service classifications for the 2010-15 regulatory control period. Italicised terms are defined in the NER.[225]

Direct control (standard control) services

B.1. 'Standard' network services

a. All *network services* except:

   i. *network services* provided at the request of a *distribution network user:*

      1. with higher quality or reliability standards, or lower quality or reliability standards (where permissible), than are required by the NER, the *Electricity Distribution Code*, or any other applicable regulatory instruments, or

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

   ii. extension or augmentation of the *distribution network* associated with the provision of a new *connection point* or upgrading of the capability of a connection point to the extent that a *distribution network user* is required to make a financial contribution in accordance with the *Electricity Distribution Code*, or

   iii. other *networks services* that are classified as *negotiated distribution services* in sections B.7 to B.16 of this appendix B.

B.2. 'Standard' connection services

a. All *connection services* except:

   i. *connection services* provided at the request of a *distribution network user*:

      1. with higher quality or reliability standards, or lower quality or reliability standards (where permissible), than are required by the NER, the *Electricity Distribution Code*, or any other applicable regulatory instrument, or

[225] The *Electricity Distribution Code* refers to the document of that name published by ESCOSA.

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

ii. the provision of a new *connection point* or upgrading of the capability of a *connection point* to the extent a *distribution network user* is required to make a financial contribution in accordance with the *Electricity Distribution Code*, or

iii. other *connection services* that are classified as *negotiated distribution services* in sections B.7 to B.16 of this appendix B.

B.3. 'Fixed' 'standard' 'small' customer metering services

a. The provision of *energy data services* in respect of meters meeting the requirements of a *metering installation* type 6 to the extent that the costs of providing the service are not avoidable where ETSA Utilities ceases to provide the associated meter provision service

B.4. Unmetered metering services

a. The provision of metering services in respect of meters meeting the requirements of a *metering installation* type 7

Direct control (alternative control) services

B.5. 'Variable' 'standard' 'small' customer metering services

a. The provision of:

i. meter provision services in respect of meters meeting the requirements of a *metering installation* type 6, and

ii. *energy data services* in respect of meters meeting the requirements of a *metering installation* type 6 to the extent that the costs of providing the service are avoidable where ETSA Utilities ceases to provide the associated meter provision service

B.6. 'Exceptional' large customer metering services

a. Meter provision services provided in respect of meters meeting the requirements of a *metering installation* type 1, *metering installation* type 2, *metering installation* type 3 or *metering installation* type 4 installed prior to 1 July 2000

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

Negotiated distribution services

B.7. 'Non-standard' network services

a. *Network services* provided at the request of a *distribution network user*:

   i. with higher quality or reliability standards, or lower quality or reliability standards (where permissible), than are required by the NER, the *Electricity Distribution Code*, or any other applicable regulatory instruments, or

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

B.8. 'Non-standard' connection services

a. *Connection services* provided at the request of a *distribution network user*:

   i. with higher quality or reliability standards, or lower quality or reliability standards (where permissible), than are required by the NER, the *Electricity Distribution Code*, or any other applicable regulatory instrument, or

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

B.9. New and upgraded connection point services

a. Extension or augmentation of the *distribution network* associated with the provision of a new *connection point* or upgrading of the capability of a *connection point* to the extent that a *distribution network user* is required to make a financial contribution in accordance with the *Electricity Distribution Code*

b. The provision of a new *connection point* or upgrading of the capability of a *connection point* to the extent a *distribution network user* is required to make a financial contribution in accordance with the *Electricity Distribution Code*

c. Responding to an enquiry in relation to the provision of a new *connection point* referred to in paragraph B.9(a) or (b)

d. Providing technical specifications in relation to the upgrading of the capability of a *connection point* referred to in paragraph B.9(a) or (b)

B.10. 'Non-standard' 'small' customer metering services

a. In relation to 'small' *distribution network users* (at present, those consuming less than 160MWh per annum), the provision of metering services:

i. 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 or *metering installation* type 5 is or is to be installed, to the extent that:

1. the charges for such services exceed the charges for the provision of *energy data services* in respect of meters meeting the requirements of *metering installation* type 6 that are not avoided where ETSA Utilities ceases to provide the association meter provision service

ii. 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 is installed at the request of a retailer or a *distribution network user*, to the extent that:

1. the charges for such services exceed the charges for the provision of *energy data services* in respect of meters meeting the requirements of *metering installation* type 6 that are not avoided where ETSA Utilities ceases to provide the association meter provision service, or

2. the charges for such services exceed the charges for the provision of metering services in respect of *metering installations* type 7 containing a meter of the type that ETSA Utilities would ordinarily install (as the case may be).

b. In relation to energy data services, the provision of special meter readings and associated services

B.11. 'Large' customer metering services

a. The provision of metering services to 'large' customers (at present, those consuming more than 160MWh per annum), except for:

i. meter provision services provided in respect of meters meeting the requirements of a *metering installation* type 1, *metering installation* type 2, *metering installation* type 3 or *metering installation* type 4 installed prior to 1 July 2000, or

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

B.12. Public lighting services

a. Street lighting use of system (SLUOS) services

i. The provision of public lighting assets, and the operation and maintenance of those assets where ETSA Utilities retains ownership of the assets.

b. Customer lighting equipment rate (CLER) services

i. The replacement of failed lamps in customer-owned streetlights where the customer retains ownership of the assets and is responsible for all other maintenance.

c. Energy only services

i. The maintenance of a database relating to street lights, and recording and informing customers of streetlight faults reported to ETSA Utilities where customers retain ownership of the assets and are responsible for all maintenance (including replacement of failed lamps).

B.13. Stand-by and temporary supply services

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

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

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

iii. provision of temporary supplies, and

iv. provision of reserve (duplicate) supply.

B.14. Asset relocation, temporary disconnection and temporary line insulation services

a. 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*.

B.15. Embedded generation services

a. Services and system augmentation or extension required to receive energy from an embedded generator and meet the requirements of the NER.

B.16. Other Services

a. The following services provided in connection with the *Electricity Distribution Code*, *Electricity Metering Code* or the NER:

i. application for an account or new supply;

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

iii. provision of old billing data;

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

v. after-hours reconnection;

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

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

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

c. Investigation and testing services

d. Asset location and identification services

e. The transportation of electricity not consumed in the *distribution system*

f. The transportation of electricity to *distribution network users* connected to the distribution system adjacent to the transmission system

g. Repair of equipment damaged by a *distribution network user* or a third party;

h. Provision of:

i. high load escorts

ii. measurement devices

iii. protection systems, and

iv. pole attachments, ducts or conduits (excluding for the provision of telecommunications services)

Appendix C: An Analysis of the Form of Control Proposed By ETSA Utilities for the 2010-15 Revenue Reset: Report to the AER

Darryl Biggar
October 2008

Introduction

As part of the AER's distribution determination for ETSA Utilities for the 2010-15 regulatory control period, the AER must publish a "Framework and Approach" paper which, amongst other things, sets out the AER's proposed approach to the classification of the services provided by ETSA Utilities and the proposed form of control applying to each class of services.

On 30 June 2008 the AER published its "Preliminary Positions" on the framework and approach, and invited submissions. In that paper the AER proposes that the majority of the services provided by ETSA Utilities be classified as "direct control services" and further as "standard control services".[226] Furthermore, in regard to the form of control to apply to these services, the AER proposed maintaining the form of control currently applied to ETSA Utilities' prescribed services. This form of control is a variant of an average revenue cap.[227]

In response, in a submission to the AER, ETSA Utilities proposed the use of a "weighted average price cap" ("WAPC") or "tariff basket" form of control for ETSA Utilities "standard control services".[228] This note compares the "weighted average price cap" form of control with the existing "average revenue cap" form of control using the statutory criteria set out in the National Electricity Rules. As we will see, this note concludes that there are grounds for coming to the view that the WAPC is the preferred form of control.

The need to specify the details of the proposed WAPC

At the most fundamental level, a WAPC form of control allows the regulated firm some discretion in choosing the individual prices of its services, subject to a cap on the weighted average of its tariffs or prices.

However, a full specification of all the details of a WAPC approach requires a number of questions to be answered, such as:

[226] The relevant services are: Network services provided to a mandated standard; Connection services at a mandated standard; Small customer standard meter provision and energy data services excluding special meter reads (type 6-7 metering installations). AER, Preliminary Positions, table 2.4 and table 2.5.

[227] The relevant legislation in South Australia (the Electricity Pricing Order) requires that "incentive based" regulation be applied to "average revenue". Clause 7.2(a) Electricity Pricing Order (pursuant to section 35B of the SA Electricity Act 1996).

[228] ETSA Utilities, *Submission to AER's Preliminary positions – Framework and approach paper – ETSA Utilities 2010-15*, Submission in response, August 2008, p. 8.

- How are the "weights" in the weighted average determined?
- How is the overall threshold or cap determined, and how does it adjust over time?
- How is the weighted average adjusted as new services are introduced over time, or as old services are phased out?
- How are other incentive mechanisms taken into account, such as a reward for pursuing "demand management" programmes or a reward for service quality improvements?

The precise form of the WAPC proposed to be adopted for ETSA Utilities is set out in Appendix D to this document.

As can be seen in Appendix D, the AER proposes using weights in the WAPC based on sales quantities two years earlier and prices charged one-year earlier. In addition, the cap on the weighted-average prices is allowed to vary over time by the CPI adjusted for a number of additional factors – the "X' factor, the "S" factor, the "D" factor, the "U" factor, and the "EDPD" factor.

The X factor is a number determined by the AER. Under the AER's proposed PTRM model, this factor is used to smooth the revenue stream over the regulatory period. The S, D, and U factors relate to the incentives for service standards, demand management, and undergrounding, respectively. The EDPD factor is a transitionary measure to carry over adjustments made under the previous determination.

In addition to the material set out in Appendix D the AER will need to specify how the WAPC will be adjusted in the event of a change in the structure of a tariff, the addition of a new tariff, or a phase-out of an old tariff. Further work will be required to define in detail the procedures to apply to account for a change in the structure of the tariffs. Such procedures have been developed by IPART in the context of the New South Wales distribution price determination. See, for example, attachment 4.1 to the Energy Australia Regulatory Submission 2008.

In addition, further work will be needed to determine precisely how the EBSS will be integrated into the WAPC.

ETSA currently has 32 tariff classes, and 288 individual tariffs/prices. Under the WAPC, historic quantities (or estimated quantities in the case of new tariffs) would have to be determined in order to calculate the relevant weights for each of these tariffs.

Comparison of the "average revenue cap" approach with the proposed WAPC approach

The following sections compare the merits of the "average revenue cap" approach with the proposed WAPC approach using the criteria set out in the "Preliminary position" paper:

- Incentives and risks
- The need for efficient prices
- The desirability for consistency; and
- Administrative costs

Incentives and risks

Under the "average revenue cap" form of control proposed in the "Preliminary positions" paper, the total volume of electricity distributed by ETSA Utilities is divided up into ten customer classes. For each customer class, there is an associated, pre-defined "average distribution revenue" or ADR. The total revenue earned by ETSA Utilities in any one year is not allowed to exceed the ADR for each customer class multiplied by the volume of electricity distributed in that customer class.

In addition, since the volume of sales in one year is not known until the end of that year, there is an "unders and overs" mechanism. This mechanism allows any under-recovery of revenue relative to the target in one year to be made up through higher prices in the subsequent year. Similarly, any over-recovery in revenue relative to the target in one year must be offset through lower prices in the next year.

Both the AER and ETSA Utilities recognise that this form of control has certain undesirable properties. These undesirable properties arise because of the mismatch between the structure of revenues that arises under average revenue regulation, and the underlying structure of costs of ETSA Utilities.

In common with the other electricity distributors in Australia, it is likely that the primary cost drivers for ETSA Utilities are factors such as the total number of customers and the total capacity of the network to deliver power to each customer. The total volume of electricity delivered is not directly a cost driver. However, the overall demand for electricity affects costs indirectly – through its effect on the peak demand for each customer (or, more precisely, the coincident peak on the bottleneck elements of the infrastructure), and through an increase in the number of customers.

Under an "average revenue cap", the revenue received by ETSA Utilities is sensitive to electricity volumes in each customer class, whereas (as just noted) the underlying costs incurred by ETSA Utilities are unlikely to vary directly with electricity volumes. The AER notes that the incentive and risk properties of the average revenue cap:

> "… 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."[229]

In the same way, ETSA Utilities also notes that problems with the average revenue cap arise "due to a misalignment of the drivers of costs and revenues" which "have created significant challenges for economic regulators and businesses alike".230

This mismatch between the structure of revenues and the structure of the underlying costs gives rise to several undesirable incentive/risk properties:

- Exposure of ETSA Utilities and its customers to risk (i.e., volatility in profit/cash-flow stream, e.g., if a high-demand year is followed by a low-

[229] AER, *Preliminary positions – Framework and approach paper – ETSA Utilities 2010-15*, June 2008, p.54. Similarly, ETSA Utilities notes that "distributor's costs are largely driven by peak demand, whereas revenues are typically aligned to energy transported through the network". ETSA Utilities, *Submission in response,* op. cit., p 9.

[230] ETSA Utilities, *Submission in response,* op. cit., p 10.

demand year). This risk applies to both the forecast volumes (which affects the allowed average distribution revenue for each customer class) and the out-turn volumes. Customers face increased price volatility as any under or over-recovery in a given year is reflected in changes in prices in subsequent years;

- Inefficient incentives to provide services – ETSA Utilities has incentives to expand services to the highest volume customers and to resist expansion, or withdraw from serving the lowest-volume customers.
- Incentives to price inefficiently – ETSA Utilities has an incentive to subsidise electricity consumption, and to encourage higher-volume customers on to the network.
- Incentives to resist demand management schemes – since any reduction in electricity volumes reduces ETSA Utilities' revenue and profit/cash-flow.
- Incentives to try to argue for low forecast electricity sales (in order to induce higher allowed average distribution revenue per unit of electricity sold).

These problems are clearly recognised by the AER in its "Preliminary positions" paper. The AER notes that the average revenue cap has 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)."[231]

Some of these undesirable incentives are also recognised by ESCOSA, who observe that:

> "There is a conflict between the incentives generated under average revenue regulation and the demand management initiatives that have been supported in this Price Determination …. Indeed, the average revenue controls required to be adopted under the EPO might not be in the long term interests of consumers".[232]

In addition, under the existing framework applying to ETSA Utilities, there is a "side constraint" limiting the rate of change of prices for individual services to CPI+3.5 per cent. The AER, due to clause 6.18.6 of the NER is required to limit the rate of change of revenue raised from individual tariff classes to CPI+2 per cent.

ETSA Utilities expresses concern that the tighter side constraint may limit its ability to recover its allowed revenue. "This occurs because the 'over-recovery' in the high sales year would require prices to be dropped in the low sales year, compounding to

[231] AER, op. cit., p, 54.
[232] ESCOSA, 2005-2010 EDPD Part A Statement of Reasons, page 187, cited in AER, page 55.

cause a significant under-recovery, which would require a significant price rise in the following year. This can be exacerbated if underlying sales growth has also been lower (or higher) than anticipated."[233].

This is recognised by the AER which proposes that ETSA Utilities "will be allowed to claim the revenue increment it was unable to recover" in the form of a "building block increment" in the subsequent period.[234] However ETSA notes that "the addition of yet another modification (and additional complexity) to a control that already deviates significantly from standard controls in place across Australia would be undesirable."[235]

To offset some of the undesirable effects of a pure "average revenue cap", the existing form of control on ETSA Utilities (and the future form of control proposed by the AER) includes a limit on the amount by which the allowed revenue of ETSA Utilities can vary due to variation in volumes in any one customer class. Specifically, if the volume varies by more than 0.5 per cent from that forecast in any one customer class, the effect on ETSA Utilities' revenue stream is reduced by 85 per cent (i.e., the sensitivity of revenue to volume when the volume is outside the 0.5 per cent threshold is reduced to only 15 per cent of the sensitivity of revenue to volume when the volume is inside the 0.5 per cent threshold). This is achieved through an adjustment to the basic average revenue cap known as a "Q-factor".

ETSA Utilities observes that the "Q factor" was put in place to approximate a revenue cap and thereby to mitigate the "high risk of errors in sales forecasts to both ETSA Utilities and customers, given the unique circumstances of the time (AGL's 30 per cent retail price increase in 2003 and doubts about the reliability of historical sales data), whilst also reducing disincentives to undertake demand management"[236]

However, even with the Q-factor component, ETSA Utilities retains concerns about the incentive and risk properties of the proposed form of control. These concerns arise because of the remaining mismatch between the structure of revenues and the structure of costs. Specifically, ETSA Utilities remains concerned about uncertainty and volatility in growth in demand for electricity and the impact on their profit/cash-flow.

As mentioned above, under the "average revenue cap" approach (i.e., the current approach in the absence of the Q-factor), ETSA Utilities' revenue is sensitive to electricity sales volumes but its expenditure is sensitive to the numbers of new customers and the magnitude of peak demand. The Q-factor reduces the sensitivity of ETSA Utilities' revenue to electricity sales volumes, but the sensitivity of expenditure to new connections and peak capacity remains. ETSA argues that future growth in SA is difficult to predict as it depends on:

> "the likelihood of the major Olympic Dam expansion going ahead, and subsequent flow-on benefits to the rest of the state, and the impact of

233 ETSA Utilities, *Submission in response,* op. cit., p 11.

234 AER, op. cit., p, 59. The AER seems to link this problem of potential under-recovery to the "Application of the Q-factor component of the form of control (due to the side constraint)". In my view, this risk of under-recovery arises from the interaction of the side-constraint with the control on the total allowed revenue. This problem of under-recovery would arise under the "average revenue cap" with or without the Q-factor component.

235 ETSA Utilities, *Submission in response,* op. cit., p 11.

236 ibid, p, 9.

> Government policy seeking to maintain the recent high growth experienced in the State"[237]

ETSA Utilities' expresses concern that should a high-growth scenario eventuate it could be required to spend in excess of $300 million in capital works to reinforce the existing network (relative to a moderate growth scenario) whereas "under the current control, ETSA Utilities would receive little additional revenue to offset these additional costs, and would thus have difficulty funding the required works"238. ETSA Utilities argues that "this was the situation faced by the New South Wales distributors over the 1998 to 2004 regulatory period and a contributing factor to the decision by IPART to move from a revenue cap to a tariff basket" form of control.

Let's turn now to look at the incentive and risk properties of the WAPC or "tariff basket" form of control. As we will see, it is not possible to be definitive in advance as to the incentive or risk properties of this form of control as it depends on how the prices are chosen.

As noted earlier, the incentive and risk properties of a form of control depend on the match between the structure of revenue and the structure of the costs incurred by the DNSP. Under the WAPC or "tariff basket" form of control there is no ex post "unders and overs mechanism". The revenue received by a DNSP is simply the revenue collected through sales each period. As a result, the structure of the revenue received by the DNSP depends entirely on how its prices are structured. If that structure of prices closely matches the structure of costs, the DNSP faces relatively little risk and has no particular incentive to serve or not to serve any customer or group of customers.

In contrast, if the DNSP chose to base its charges entirely on the volume of electricity distributed, the WAPC would have properties similar to the "average revenue cap" discussed above. In the same way, if the DNSP chose to base its charges entirely on the number of customers, while its costs depend on both the number of customers and the peak network capacity, the DNSP would be insulated from risk of an unforecast change in customer numbers but would face the risk of a substantial increase in the need for network capacity.

In general, then, under a WAPC, the precise incentive and risk properties depend on the structure of prices chosen. Nevertheless, as a starting point, it seems reasonable to assume that a WAPC form of control, using prices similar to those in place at present, would result in a structure of revenue more closely matched to the structure of the underlying costs than the "average revenue cap" discussed above.

In particular, it seems that, in the event of an increase in the number of customer connections, or the peak load of the network, the revenue under a WAPC would increase to at least partially reflect the required increase in costs. Therefore ETSA Utilities is probably correct to argue that:

> "With a tariff basket in place, there is, to some extent, a natural hedge between economic growth and the requirement for additional funding when a high growth scenario occurs. The hedge is imperfect, as it relies on the relationship between sales and demand growth being maintained … but is clearly superior

[237] ibid, p, 12.
[238] ibid, p, 12.

> to the situation under the current control where little or no additional revenue is received to offset the additional cost".[239]

At the same time, there is some theoretical foundation for the view that if the "weights" in the WAPC are chosen correctly, the DNSP will have an incentive to structure its prices efficiently – that is, bringing marginal prices down to marginal cost (as much as possible) and recovering fixed costs through "fixed" charges. Theoretically, if the weights in the WAPC are based on "lagged" quantities (i.e., quantities of sales in the most recent period)[240], and if the DNSP charges are passed on to consumers, if the DNSP is not too "forward looking", and if the commercial environment (i.e., costs and demands) is relatively stable, the resulting prices will evolve towards the theoretical efficient ("Ramsey") prices. In other words, there is some theoretical foundation for the view that, under the WAPC, the prices will evolve to broadly reflect the structure of costs.[241]

However, for this result to occur, the conditions noted above must hold. In particular, the DNSP charges must be passed on to consumers. In practice, I understand that retailers do not regularly pass on distribution charges directly but "bundle" them into the tariffs they offer to their retail customers. This obscures the price signals received by the DNSP and might induce the DNSP to alter its prices in perverse ways. The AER recognises that the extent to which end-users respond to distribution charges is an issue which remains unclear:

> "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."[242]

ETSA recognises this concern that the distribution prices may not be passed on via retailers to customers, but they note that "within the current period, retailers have passed on to customers all pricing signals initiated by ETSA Utilities".[243] It is unclear whether this means that retailers have passed on the structure of ETSA's charges, or the level or both.

In addition, it is worth noting that at present ETSA Utilities still recovers the vast bulk (three-quarters) of its revenue through charges which vary with the volume of electricity sold. (see Figure 1). Therefore, even under the WAPC approach, at least in the short term:

- ETSA Utilities' revenue will still be heavily exposed to variation in the volume of electricity sales. In other words, ETSA Utilities will continue to face significant risk arising from variation in weather and economic growth. It is possible that this will lead to requests for further modification to the form

239 ibid, p, 12.

240 In practice, the weights in the WAPC are based on sales volumes lagged two periods. I am not aware of any theoretical proof that this approach is efficient, but, in the absence of evidence to the contrary, as long as the environment is relatively stable, we could assume that this approach will be adequate.

241 Section 18(5) of the National Electricity (South Australia) Act 1996 requires that the AER must set geographically uniform tariffs to small customers for network services. This limits, somewhat, the extent to which the DNSP tariffs can be truly cost reflective.

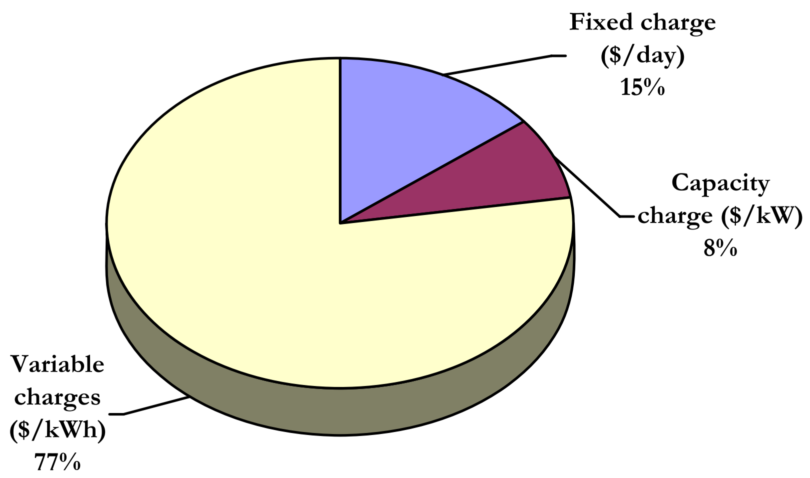
242 AER, op. cit., p, 57.

243 ETSA Utilities, *Submission in response,* op. cit., p 14.

of control in the future (such as limits on the variation in revenue to which ETSA Utilities is exposed).

- ETSA Utilities will retain incentives to oppose demand management initiatives (although this incentive will, in part, be mitigated through the demand management compensation mechanism).
- ETSA Utilities will retain incentives to expand service to high volume customers while reducing service to low-volume customers (although this incentive is, presumably, controlled through other service obligations).

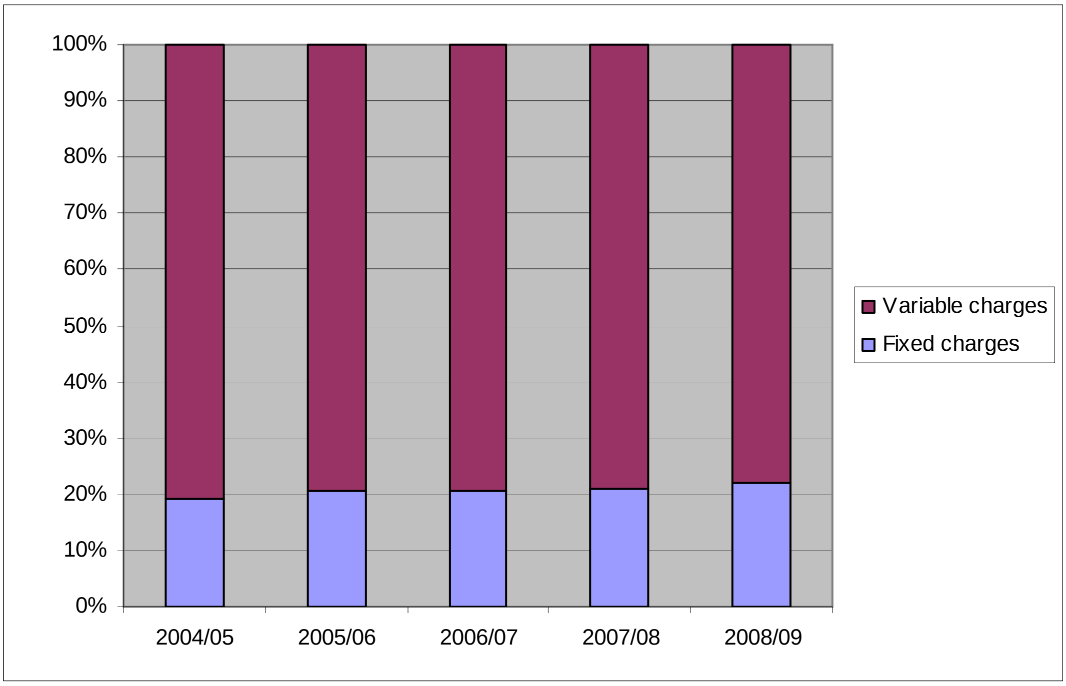
Figure 1: Break-down of fixed versus variable charges ETSA Utilities 2006-07



Source: ETSA Utilities Tariff Submission 2006-07 v2.0.

It is my understanding that ETSA Utilities, in meetings with the AER, expressed a desire for further rebalancing of its tariffs and a move towards more "capacity based" tariffs. This move will further mitigate the incentives noted above. There is some evidence of slow rebalancing in the past. As Figure 2 shows, focusing only on the largest-revenue tariff classes, fixed charges have increased from 19.1 per cent to 22 per cent of total revenue in the past 5 years (data for 07/08 is missing).

Figure 2: Share of ETSA Utilities revenue from fixed/variable charges



As an aside, note that any rebalancing of tariffs should be structured so as to not disadvantage existing customers. Some customers (such as those with low or intermittent use, such as owners of holiday houses or weekend retreats) could be made worse off through a substantial rebalancing of tariffs. Ideally, rebalancing should occur through the introduction of new tariffs, and allowing customers the option of choosing the alternative structure. This minimises the risk that existing customers are made worse off.

Overall, on the basis of incentive and risk properties, it seems clear that:

- The existing average revenue cap has undesirable properties. These undesirable properties are partially mitigated by the Q-factor.
- The precise incentive and risk properties of a WAPC depend on the choice of prices (and, in particular, how the prices are structured relative to costs). In the short-term, the revenue of ETSA Utilities will still be dominated by revenue from variable charges. It is unlikely this structure of charges closely reflects the cost structure of ETSA Utilities. Therefore, in the short term at least, ETSA Utilities will continue to face some risk and will retain some undesirable incentives. Over time, however, there are reasons for expecting that ETSA Utilities will move to a tariff structure that more closely reflects the structure of its underlying costs. This will improve the risk and incentive properties. Overall, it seems likely that a WAPC would – at least over time - give rise to improved incentive and risk properties than the status quo.

On the basis of incentive and risk properties, there are grounds for favouring the WAPC approach. Consideration could be given to further rebalancing of the structure of prices (subject to an assessment of the impact on retail customers).

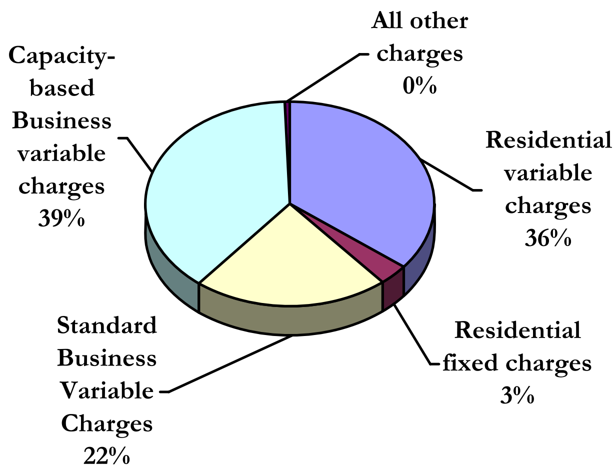
The need for efficient prices

As noted above, the average revenue cap form of control is not likely to lead to an efficient price structure. The WAPC approach may, under certain assumptions, yield efficient and cost-reflective prices. As ETSA notes, "the tariff basket is generally recognised by economists as being the control that provides the greatest incentive for distributors to price cost reflectively".244

However, as noted above, the current structure of tariffs of ETSA Utilities does not reflect its underlying structure of costs. It may take some time for ETSA Utilities to move to a more efficient tariff structure.

The following graph shows the weighting of different groups of charges in ETSA Utilities' WAPC. Residential variable charges account for 35.2 per cent, while residential fixed charges account for only 3.2 per cent. My calculations suggest for example, that ETSA Utilities could raise the residential fixed charges by 10 per cent and reduce the residential variable charges by 3 per cent and still satisfy the overall price cap. Similarly, it appears that ETSA could raise the commercial capacity-based charges by 10 per cent and lower the corresponding variable charges by 7 per cent and still satisfy the overall price cap.[245] It is my understanding that the CPI+2 per cent side constraint set out in the NER would not prevent rebalancing of this kind.

Figure 3: Weightings of different types of charges in the WAPC (based on 06-07 quantities)



It is not certain that efficient prices will emerge under the WAPC. However, the likelihood of efficient prices emerging is higher than under the average revenue cap form of control. On the basis of the "need for efficient tariff structures", the WAPC form of control seems preferable to the status quo.

Desirability of consistency

As ETSA notes, the WAPC is used in New South Wales and Victoria, accounting for more than 60 per cent of the NEM by energy volume. The use of a WAPC in SA would be consistent with these other jurisdictions. On the basis of the "desirability of consistency between regulatory arrangements for similar services", the WAPC form of control seems preferable to the status quo.

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[244] ETSA Utilities, *Submission in response*, op. cit., p 14.
[245] Assuming that quantities remain essentially unchanged following the adjustment to prices.

Administrative costs

It is difficult to judge the administrative costs of either approach. In terms of complexity, the average revenue cap approach is potentially slightly simpler to understand and to implement, but in practice, the proposed average revenue cap, with the Q-factor, S-factor and U-factor adjustments is relatively complex and not clearly any simpler to implement than a WAPC.

ETSA Utilities claims that the AER's costs would "potentially reduce by virtue of a reduction in the number of revenue control variations across Australia, and by removing the need to review sales forecasts when considering annual pricing submissions from ETSA Utilities".[246]. I am not sure what ETSA mean by "revenue control variations". The second point ETSA makes seems valid – the AER would only need information on historic sales when verifying annual pricing changes. The AER would still need to verify sales forecasts when setting the opening prices each regulatory control period.

The WAPC approach does away with the need for an "unders and overs" mechanism to account for under- or over-recovery at the end of each year.

Overall, on the basis of the "possible effects of the control mechanism on administrative costs of the AER, the DNSP and users or potential users", there is no clear ground for preferring either form of control.

Other factors

ETSA Utilities note that the WAPC form of control would likely reduce price volatility – both within the regulatory control period and between regulatory control periods. This seems likely to be the case.

Overall, ETSA Utilities considers "That there are a number of significant deficiencies in the current revenue control that would make it highly undesirable to apply to the next period"[247] and that there is "a strong and reasonable basis to move from the current control to a weighted average price cap or 'tariff basket'" form of control.[248]

Conclusion

In my view, having regard to the factors the AER is required to consider under section 6.2.5(c) of the NER, and in the light of the information and experience currently available, there are grounds for preferring the WAPC form of control over the form of control set out in the "Preliminary positions" paper.

The advantages of the WAPC form of control depend on the structure of prices chosen by ETSA Utilities over time. As noted above, the current price structure is not particularly reflective of the underlying structure of costs. Some adverse incentives and risks will remain at least in the short-term. However ETSA Utilities has expressed an intention to rebalance its prices. The WAPC approach allows and encourages such rebalancing. This process will (slowly) mitigate the adverse impact of the current price structure.

Some questions remain – notably about (a) precisely how new tariffs will be incorporated into the price cap and (b) the extent to which these distribution tariffs will be passed on to end-users. This could be the subject of future work.

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246 ETSA Utilities, *Submission in response,* op. cit., p 14.
247 ETSA Utilities, *Submission in response,* op. cit., p 14.
248 ibid, p, 8.

It would be useful to keep in mind the possibility of a review of the WAPC form of control in a few years time, to assess the extent of rebalancing and the extent to which these tariffs have been passed on to end-users.

Appendix D: Form of control mechanisms to be applied by the distribution determination

Standard control services

The weighted average price cap distribution price control is expressed by the formula set out below.

$$\left(1+CPI_t\right)\times\left(1-X\right)\times\left(1+S_t\right)\times\left(1+D_t\right)\times\left(1+U_t\right)\times\left(1+EDPD_t\right)\geq\frac{\sum_{i=1}^{n}\sum_{j=1}^{m}p_t^{ij}\times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m}p_{t-1}^{ij}\times q_{t-2}^{ij}}$$

where ETSA Utilities has *n distribution tariffs*, which each have up to *m distribution tariff components*, and where:

regulatory year "t" is the *regulatory year* in respect of which the calculation is being made;

regulatory year "t-1" is the *regulatory year* immediately preceding *regulatory year "t"*;

regulatory year "t-2" is the *regulatory year* immediately preceding *regulatory year "t-1"*;

p_t^{ij} is the proposed *distribution tariff* for component *j* of *distribution tariff i* in *regulatory year t* ;

p_{t-1}^{ij} is the *distribution tariff* being charged in *regulatory year t-1* for component *j* of *distribution tariff i;*

q_{t-2}^{ij} is the quantity of component *j* of *distribution tariff i* that was delivered in *regulatory year t-2*;

CPI_t is calculated as follows:

> The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the March Quarter immediately preceding the start of *regulatory year t*;

divided by

> The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the March Quarter immediately preceding the start of *regulatory year t-1*;

X to be determined using the building block approach;

S_t is the Service Target Performance Incentive Scheme factor to be applied in *regulatory year t*;

D_t is the Demand Management Incentive Scheme factor to be applied in *regulatory year t*;

U_t is the Undergrounding factor to be applied in *regulatory year t*;

$EDPD_t$ is the EDPD Transition Factor for *regulatory year t*. It is a carryover of adjustments made in the 2005-2010 EDPD comprising the previous K, Q, P U and SI factor adjustments.

Note – when determining the D_t, U_t, and $EDPD_t$ (and possibly S_t) factors, the Smoothed Revenue Requirement from the 2010-15 Determination (escalated for actual CPI movements) for each relevant *regulatory year* will be utilised to convert the whole dollar amounts to percentages for use in the tariff basket formula. This is the methodology applied when calculating the D Factor under the current 2004-2009 New South Wales Electricity Price Determination.

ETSA Utilities will be required to include proposed distribution tariff classes (n) and components (m) in its regulatory proposal to the AER.

Alternative control services

The basis of control mechanism for alternative control services will be of the CPI – X form.

The weighted average price cap distribution price control is expressed by the formula set out below.

$$\left(1+CPI_t\right)\times\left(1-X\right)\geq\frac{\sum_{i=1}^{n}\sum_{j=1}^{m}p_t^{ij}\times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m}p_{t-1}^{ij}\times q_{t-2}^{ij}}$$

where ETSA Utilities has *n distribution tariffs*, which each have up to *m distribution tariff components*, and where:

regulatory year "t" is the *regulatory year* in respect of which the calculation is being made;

regulatory year "t-1" is the *regulatory year* immediately preceding *regulatory year "t"*;

regulatory year "t-2" is the *regulatory year* immediately preceding *regulatory year "t-1"*;

p_t^{ij} is the proposed *distribution tariff* for component *j* of *distribution tariff i* in *regulatory year t* ;

p_{t-1}^{ij} is the *distribution tariff* being charged in *regulatory year t-1* for component *j* of *distribution tariff i;*

q_{t-2}^{ij} is the quantity of component *j* of *distribution tariff i* that was delivered in *regulatory year t-2*;

CPI_t is calculated as follows:

> The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the March Quarter immediately preceding the start of *regulatory year t*;

divided by

> The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the March Quarter immediately preceding the start of *regulatory year t-1*;

X to be determined using the building block approach;

ETSA Utilities will be required to include proposed distribution tariff classes (n) and components (m) for both variable standard small customer metering services and exceptional case metering services in its regulatory proposal to the AER..

Glossary

$	dollars
±	plus minus
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AER	Australian Energy Regulator
capex	capital expenditure
CBD	central business district
Centurion	Centurion Metering Technologies
Cl.	clause
CLER	customer lighting equipment rate
Cll.	clauses
CPI-X	CPI minus X
CRA	Charles River Associates
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DNSP	distribution network service provider
DUOS	distribution use of system
EBSS	efficiency benefit sharing scheme
EDPD	Electricity Distribution Price Determination
EPO	Electricity Price Order
ESCOSA	Essential Services Commission of South Australia
GSL	Guaranteed Service Level
GWh	Gigawatt hours
HV	high voltage
IEEE	Institute of Electrical and Electronics Engineers
LGA	Local Government Association of South Australia
ln	natural logarithm
LNSP	local network service provider

MADR	maximum allowable distribution revenue
MAIFI	momentary average interruption frequency index
MAR	maximum allowable revenue
MCE	Ministerial Council on Energy
MED	major event day
Metropolis	Metropolis Metering Assets
MWh	Megawatt hours
NEC	National Electricity Code
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company Limited
NER	National Electricity Rules
NSW	New South Wales
OMS	Outage Management System
opex	operating expenditure
Origin	Origin Energy Retail
P-factor	profit sharing mechanism
PTRM	post-tax revenue model
RAB	regulatory asset base
RFM	roll-forward model
RIN	Regulatory Information Notice
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
SI scheme	Service Incentive Scheme
SLUOS	street lighting use of system

SORI	statement of regulatory intent
STPIS	service target performance incentive scheme
TEC	Total Environment Centre
TMED	major event day threshold
VCR	value of customer reliability
VENCorp	Victoria Energy Networks Corporation
WAPC	weighted average price cap