



Preliminary positions paper
Framework and approach for
SA Power Networks
Regulatory control period commencing 1 July
2015

December 2013

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Request for submissions

Interested parties are invited to make written submissions to the Australian Energy Regulator (AER) regarding this paper by the close of business, 19 February 2014.

Submissions should be sent electronically to: SAelectricity2015@aer.gov.au

Alternatively, submissions can be mailed to:

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

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

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

Enquiries about this paper, or about lodging submissions, should be directed to the Network Regulation branch of the AER on (02) 9230 9133.

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Shortened forms

Shortened Form	Extended Form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	capital expenditure
CESS	capital expenditure sharing scheme
CPI	consumer price index
CPI-X	consumer price index minus X
current regulatory control period	1 July 2010 to 30 June 2015
DMIA	demand management incentive allowance
DMIS	demand management incentive scheme
DNSP or distributor	distribution network service provider
DUOS	distribution use of system
EBSS	efficiency benefit sharing scheme
ESCOSA	Essential Services Commission of South Australia
F&A	Framework and approach
GSL	guaranteed service level
kWh	kilowatt hours
MAR	maximum allowable revenue
MWh	megawatt hours
NECF	National Energy Customer Framework
NEL or the law	National Electricity Law
NEO	National Electricity Objective
NEM	National Electricity Market
NER or the rules	National Electricity Rules
opex	operating expenditure
RAB	regulatory asset base
SA	South Australia
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index

SAPN	SA Power Networks
SCER	Standing Council on Energy and Resources
SCONRRR	Standing Committee on National Regulatory Reporting Requirements
STPIS	Service Target Performance Incentive Scheme
WAPC	weighted average price cap

About the framework and approach

The Australian Energy Regulator (AER) is the economic regulator for transmission and distribution services in Australia's national electricity market (NEM).¹ We are an independent statutory authority, funded by the Australian Government. Our powers and functions are set out in the National Electricity Law (the law or NEL) and National Electricity Rules (the rules or NER).

The framework and approach (F&A) is the first step in a process to determine efficient prices for electricity distribution services. The F&A sets out our positions on which services we will regulate and the broad nature of any regulatory arrangements. It also facilitates early public consultation and assists network service providers prepare regulatory proposals.

SA Power Networks (SAPN) is the licensed, regulated operator of South Australia's monopoly electricity distribution network. The network comprises the poles, wires and transformers used for transporting electricity across urban and rural population centres to homes and businesses. SA Power Networks designs, constructs, operates and maintains its distribution network for SA electricity consumers.

We regulate a variety of services provided by NEM distributors. Where there is considerable scope to take advantage of market power, our regulation is more prescriptive. Less prescriptive regulation is required where the prospect of effective competition exists. In some situations we may remove regulation altogether.

In anticipation of every distribution determination, we are required to prepare and publish a framework and approach.² The F&A assists a distributor in preparing its regulatory proposal to us by setting out:

- the proposed approach to distribution service classification (which services are to be regulated)
- the form (or forms) of the control mechanisms to be applied by the distribution determination (how prices will be determined) and the proposed formulae that give effect to the control mechanisms
- the proposed approach to the application of a range of incentive schemes that encourage things like service quality, improvements in network reliability, and efficient capital and operating expenditure (capex and opex).

We will use the F&A process to commence discussions with SA Power Networks about the treatment of confidential information as set out in our confidentiality guideline.³ We encourage SA Power Networks to also consult consumers, as part of their consumer engagement, to gain a better understanding of the type of information consumers are interested in accessing.⁴

Part A of this paper sets out an overview of our preliminary positions and reasons for each of the above matters. Part B sets out our substantive reasoning on each matter.

Following release of this paper, we will consult with interested parties before issuing the final F&A. Table 1 summarises the SA distribution determination process.

¹ In addition to regulating NEM transmission and distribution, we regulate the NEM wholesale market and administer the National Gas Rules.

² NER, clause 6.8.1(a).

³ AER, *Confidentiality guideline*, 19 November 2013.

⁴ AER, *Consumer engagement guideline for network service providers*, 6 November 2013.

Table 1: SA distribution determination process

Step	Date
AER published preliminary positions F&A	18 December 2013
AER to publish final F&A	30 April 2014
SAPN submits regulatory proposal to AER	31 October 2014
Submissions on regulatory proposal close	January 2015**
AER to publish draft distribution determination	30 April 2015*
AER hold public forum on draft distribution determination	May 2015**
SAPN to submit revised regulatory proposal to AER	June 2015
Submissions on revised regulatory proposal and draft determination close	July 2015**
AER to publish distribution determination for regulatory control period	31 October 2015

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

** The dates provided for submissions and the public forum are based on us receiving compliant proposals. These dates may alter if we receive non-compliant proposals.

Source: NER, chapter 6, Part E.

Part A: Overview

This preliminary F&A positions paper covers the following issues.

Classification of distribution services

Classification is important to electricity customers because it determines the need for and scope of regulation applied to distribution services central to electricity supply. Distribution services include, for example, the provision and maintenance of poles and wires and connection or disconnection to electricity. Classification determines how the prices of these services will be set. This has a direct impact on electricity customers.

When we classify distribution services we determine the nature of the economic regulation that we will apply to those services. The rules establish a limited range of service classification categories, to which varying levels of economic regulation apply. When we classify services we therefore determine whether we directly control prices, become involved only to arbitrate disputes, or do not regulate at all. The classification that we apply to a distribution service also determines whether the relevant distributor recovers service costs by averaging across all customers or only charging those benefiting directly from specific services.

Table 2 provides an overview of the different classes of distribution services for the purposes of economic regulation under the rules.

Table 2: Classifications of distribution services

Classification		Description	Regulatory treatment
Direct control service	Standard control service	Services that are central to electricity supply and therefore relied on by most (if not all) customers such as building and maintaining the shared distribution network. Most distribution services are classified as standard control.	We regulate these services by determining prices or an overall cap on the amount of revenue that may be earned for all standard control services. The costs associated with these services are shared by all customers via their regular electricity bill.
	Alternative control service	Customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by the local distributor.	We set service specific prices to enable the distributor to recover the full cost of each service from customers using that service.
Negotiated service		Services we consider require a less prescriptive regulatory approach because all relevant parties have sufficient market power to negotiate the provision of those services.	Distributors and customers are able to negotiate prices according to a framework established by the rules. We are available to arbitrate if necessary.
Unclassified service		Services that are not distribution services ⁵ or services that are contestable.	We have no role in regulating these services.

Source: AER

The current classification of SA Power Networks' services largely reflects the arrangements that applied in SA under the previous state-based regime. The SA arrangements differ from the arrangements that apply in other NEM jurisdictions. In particular, a large number of SA Power

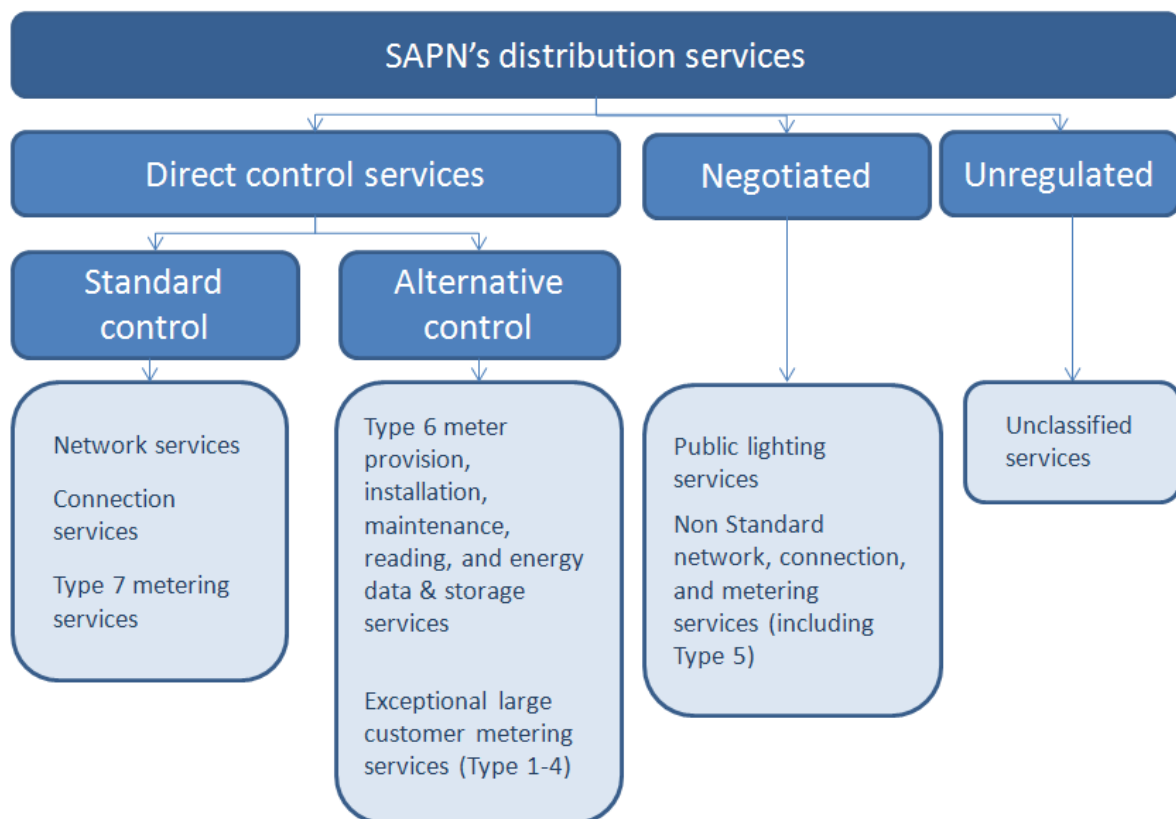
⁵ A distribution service is a service provided by means of, or in connection with, a distribution system.

Networks' services are negotiated services. This means that customers may negotiate directly with SA Power Networks for the provision of the service.⁶ Typically, these services share the common characteristic of being non-routine services provided to individual customers on an 'as needs' basis. In many cases, some or all of the service is contestable and may be provided by an alternative service provider, such as the construction of extension and connection assets. Our preliminary position is that the existing classification of these services remains appropriate.

The only proposed change to the classification of services is that all standard type 6 metering related services will now be alternative control services. Our preliminary position is that type 6 energy data services, unscheduled meter reading and metering investigation be reclassified as alternative control services. This will provide customers with more transparent costing information for these services.

Figure 1 sets out our preliminary position on the classification of SA Power Networks' distribution services, which is largely unchanged from the classifications applying in the current regulatory control period, except for a number of type 6 metering services which have been reclassified from standard control to alternative control service. Attachment 1 provides more information about the different types of services and the reasoning behind our preliminary position.

Figure 1: AER preliminary position for classification of SAPN's distribution services



Source: AER

⁶ The rules also confer a dispute resolution role on the AER in respect of negotiated services.

In developing our preliminary view, we have had regard to the factors set out in the law and rules.⁷ If stakeholders disagree with our classification, they should provide reasons why an alternative classification better meets the requirements of the law and rules.

Control mechanisms

Following on from service classifications, our determinations must impose controls on direct control service prices and/or their revenues.⁸ We may only accept or approve control mechanisms in a distributor's regulatory proposal if they are consistent with the framework and approach.⁹

The rules require us to decide the control mechanism forms¹⁰ and the formulae to give effect to the control mechanism, but not the basis of the form of control mechanism. In deciding control mechanism forms, we must select one or more from those listed in the rules.¹¹ These include price schedules, caps on the prices of individual services, weighted average price caps, revenue caps, average revenue caps and hybrid control mechanisms.

In deciding on the form of control mechanism, the rules require us to have regard to specified factors.¹² These include the need for efficient tariffs, administrative costs, previous regulatory arrangements and consistency. In light of the above alternatives and considerations, our preliminary position on the form of control mechanisms for SA Power Networks are:

- standard control services— revenue cap
- alternative control services— caps on the prices of individual services.

For standard control services, the rules mandate the basis of the control mechanism must be the prospective CPI-X form, or some incentive-based variant.¹³ For alternative control services, we will confirm a control mechanism basis through the distribution determination process.

Standard control services

Our preliminary position is to apply a revenue cap form of control for the standard control services. In developing our preliminary view, we have had regard to the factors set out in the law and rules.¹⁴ If stakeholders disagree with our classification, they should provide reasons why an alternative classification better meets the requirements of the law and rules.

Alternative control services

Our preliminary position is to apply a price cap form of control for the alternative control services. In developing our preliminary view, we have had regard to the factors set out in the law and rules.¹⁵ If stakeholders disagree with our classification, they should provide reasons why an alternative classification better meets the requirements of the law and rules.

⁷ The relevant rules are set out in Appendix A.

⁸ NER, clause 6.2.5(a).

⁹ NER, clause 6.12.3(c).

¹⁰ NER, clause 6.2.5(b).

¹¹ NER, clause 6.2.5(b).

¹² NER, clauses 6.2.5(c) and 6.2.5 (d).

¹³ NER, clause 6.2.6(a). The basis of the form of control is the method by which target revenues or prices are calculated e.g. a building block approach.

¹⁴ NER, clauses 6.2.6(a) and 6.2.6(b).

¹⁵ NER, clauses 6.2.6(a) and 6.2.6(b).

Incentive schemes

The purpose of incentive schemes is to encourage distributors to manage their businesses in a safe, reliable manner that serves the long term interests of consumers. The schemes provide distributors with incentives to only incur efficient costs and to meet or exceed service quality targets. In some instances, distributors may incur a financial penalty if they fail to meet set targets. These schemes include the service target performance incentive scheme, efficiency benefit sharing scheme, capital expenditure sharing scheme and demand management incentive scheme. The overall objectives of the schemes are to:¹⁶

- incentivise distributors to spend more efficiently on capital and operating expenditure
- reduce the risk of consumers paying for unnecessary capital expenditure
- share efficient improvements and losses between distributors and consumers
- encourage appropriate levels of service quality
- maintain network reliability as appropriate.

We outline below our preliminary position on the application of each scheme to SA Power Networks.

Service target performance incentive scheme

Our national service target performance incentive scheme (STPIS) provides a financial incentive to distributors to maintain and improve service performance. The STPIS aims to safeguard service quality for customers against incentives for the distributors to seek out cost efficiencies.

Our preliminary position is to continue to apply the national STPIS to SA Power Networks in the next regulatory control period. We will not apply the guaranteed service level (GSL) component as SA Power Networks is subject to a jurisdictional GSL scheme.¹⁷

Efficiency benefit sharing scheme

The efficiency benefit sharing scheme (EBSS) aims to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and provide for a fair sharing of these between distributors and network users. Consumers benefit from improved efficiencies through lower regulated prices.

As part of our Better Regulation program we consulted on and published version 2 of the EBSS. Our preliminary position is to apply the new EBSS to SA Power Networks in the next regulatory control period.

Capital expenditure sharing scheme

The capital expenditure sharing scheme (CESS) provides financial rewards for distributors whose capex becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices.

¹⁶ AER, *Electricity distribution network service providers, Service target performance incentive scheme*, June 2008, p. 2; AER, *Expenditure incentives guideline*, 29 November 2013.

¹⁷ ESCOSA, *Electricity Distribution Code*, clause 1.1.4. A copy of this code can be found at www.escosa.sa.gov.au/library/130131-ElectricityDistributionCode-EDC10.pdf.

As part of our Better Regulation program we consulted on and published version 1 of the capital expenditure incentive guideline for electricity network service providers (capex incentive guideline) which sets out the CESS. We propose to apply the CESS as set out in our capex incentive guideline in the next regulatory control period to SA Power Networks.

Demand management incentive scheme

Our preliminary position is to continue applying the DMIA to SA Power Networks in the next regulatory control period.

The Standing Council on Energy and Resources (SCER) is currently considering a series of rule changes¹⁸ proposed by the Australian Energy Market Commission (AEMC) in its Power of Choice review¹⁹ examining distributor incentives to pursue efficient alternatives to network augmentation. This will include new rules and principles guiding the design of a new DMIS. We intend to develop and implement a new DMIS during the next regulatory control period, depending on the progress of the rule change process.

Small-scale incentive scheme

The rules state that we may develop a small-scale incentive scheme.²⁰ We have not developed this scheme. Therefore, we will not be stating our preliminary position on the application of this scheme to SA Power Networks.

Application of the expenditure forecast assessment guidelines

We recently published our expenditure forecast assessment guideline. This guideline is based on a nationally consistent reporting framework allowing us to compare the relative efficiencies of distributors and decide on efficient expenditure allowances. Our preliminary position is to apply the guideline, including the information requirements to SA Power Networks in the next regulatory control period.

The guideline outlines a suite of assessment/analytical tools and techniques to assist our review of SA Power Networks' regulatory proposal. We intend to apply all the assessment tools set out in the guideline.

Approach to calculating depreciation

Changes to the rules require us to state our approach to calculating depreciation when we roll forward SA Power Networks' regulatory asset base (RAB) for the 2020–2025 regulatory control period. Our preliminary position is to use forecast depreciation to establish the RAB as at 1 July 2020.

The depreciation we use to roll forward the RAB can be based on actual capex incurred during the regulatory control period or alternatively, we may use the capex allowance forecast as at the start of the regulatory control period.

¹⁸ SCER, *Demand side participation – proposed rule changes*, 18 September 2013.

See: www.scer.gov.au/workstreams/energy-market-reform/demand-side-participation/proposed-rule-changes.

¹⁹ AEMC, *Final report, Power of choice review – giving consumers choice in the way they use electricity*, 30 November 2012.

²⁰ NER, clause 6.6.4.

Our preliminary position to use forecast depreciation, in combination with our proposed application of the CESS, will maintain incentives for distributors to pursue capex efficiencies. These improved efficiencies benefit consumers through lower regulated prices.

Jurisdictional derogation – side constraint to the fixed supply charge for small customers

Under clause 9.29.5 (d) of the rules, we applied the following side constraint to distribution tariffs for small customers for the 2010–15 regulatory control period:

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

However, clause 9.29.5 (e) allows us to reconsider whether the above side constraint should continue with or without modification in preparing the F&A for the 2015–2020 distribution determination.

We consider that a national approach to pricing structures should be adopted. This does not mean that price stability through constraints on tariff movements or other consumer protection measures should not be adopted. Rather, they should be considered and applied consistently. On this basis we seek stakeholder comments on whether the \$10 cap on fixed supply charge price increases should continue, with or without modification.

Dual function assets

The F&A must include our determination under clause 6.25(b) as to whether or not Part J of chapter 6A is to be applied to determine the pricing of any transmission standard control services provided by any dual function assets owned, controlled or operated by a distributor. Dual-function assets are high voltage transmission assets forming part of the distribution network. Transmission network service providers usually operate these assets. Considering transmission assets as part of a distribution determination avoids the need for a separate transmission proposal.

SA Power Networks has advised us that it does not have any dual function assets. We will therefore not make any determination under clause 6.25(b) of the rules for the purposes of this F&A.

Part B: Attachments

1 Classification of distribution services

This attachment sets out our preliminary position on our likely approach to the classification of distribution services provided by SA Power Networks. Classification determines the nature of economic regulation, if any, applicable to specific distribution services. Classification therefore determines whether we directly control prices, allow parties to negotiate services and prices and only arbitrate disputes if necessary, or do not regulate at all.²¹ If we intend to control prices directly, classification further determines whether distributors will recover service costs from all customers or only a specified subset of customers.²²

Classification is important to customers as it determines which network services are included in basic electricity charges, which services will be sold as additional services and which services we will not regulate. Largely, our decisions reflect our assessment of competition or the potential for competition of distribution services. Where there is limited competition for the provision of services, we classify services to achieve a more prescriptive form of regulation. If there is competition or the potential for competition, we provide a less prescriptive form of regulation or do not regulate the service at all. If only identifiable customers use a service, we may consider classifying these services to encourage a user pays approach to pricing.

Our role in service classification only determines the manner in which a distributor recovers the costs associated with the distribution services it provides. It does not determine the contestability of these services. For example, our classification of a distribution service as a direct control service does not make SA Power Networks the exclusive monopoly provider of that service. Likewise, our classification of a distribution service as a negotiated distribution service does not, of itself, make the service contestable and open to supply by providers other than SA Power Networks. Contestability is determined by legislation, or other regulatory instruments, and is beyond our control.

Our proposed approach to the classification of distribution services in South Australia is for the 1 July 2015 to 30 June 2020 regulatory control period. Our classifications set out in this F&A must be adopted in a distribution determination, unless we consider that unforeseen circumstances justify a different approach.²³

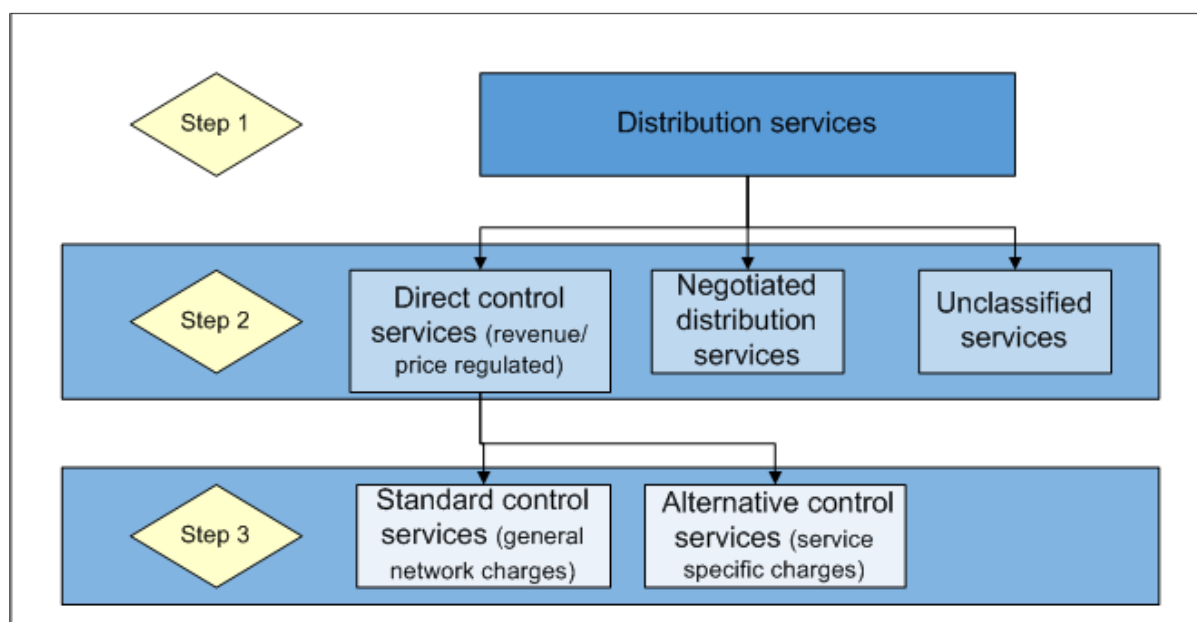
The rules set out a three stage classification process we must follow. We must consider a number of specified factors at each stage. Figure 2 outlines the classification process under the rules.

²¹ The control mechanism available for each service depends on the classification. The control mechanisms available for direct control services are listed under cl. 6.2.5(b) of the rules. These include revenue caps, average revenue caps, price caps, weighted average price caps, a schedule of fixed prices or a combination of the specified forms of control. Negotiated distribution services are regulated under the negotiate/arbitrate framework set out in Part D of chapter 6 of the rules. Control mechanisms are discussed in detail in attachment 2 of this paper.

²² In general, the costs of providing standard control services would be expected to be recovered through distribution use of service tariffs paid by all or most customers. Costs of providing alternative control or negotiated distribution services would be expected to be recovered from the individual customers that are the recipients of such services.

²³ NER, clause 6.12.3(b).

Figure 2: Distribution service classification process



Source: NER, chapter 6, part B.

First, we must determine whether a service is a 'distribution service'. At a high level, distribution services are services provided by means of, or in connection with, a distribution electricity network.²⁴

Second, we classify the distribution services. We may:

- classify a service that benefits all customers so that the distributor may attribute costs to all customers (direct control and standard control)
- classify a service so that the user benefiting from the service pays (direct control and alternative control)
- allow customers and distributors to negotiate the provision and price of some services. Our only role will be to arbitrate should negotiations stall (negotiated distribution service)
- not classify a service. In this instance, we have no regulatory control over this service or the prices charged by the distributor for the service (unclassified service).²⁵

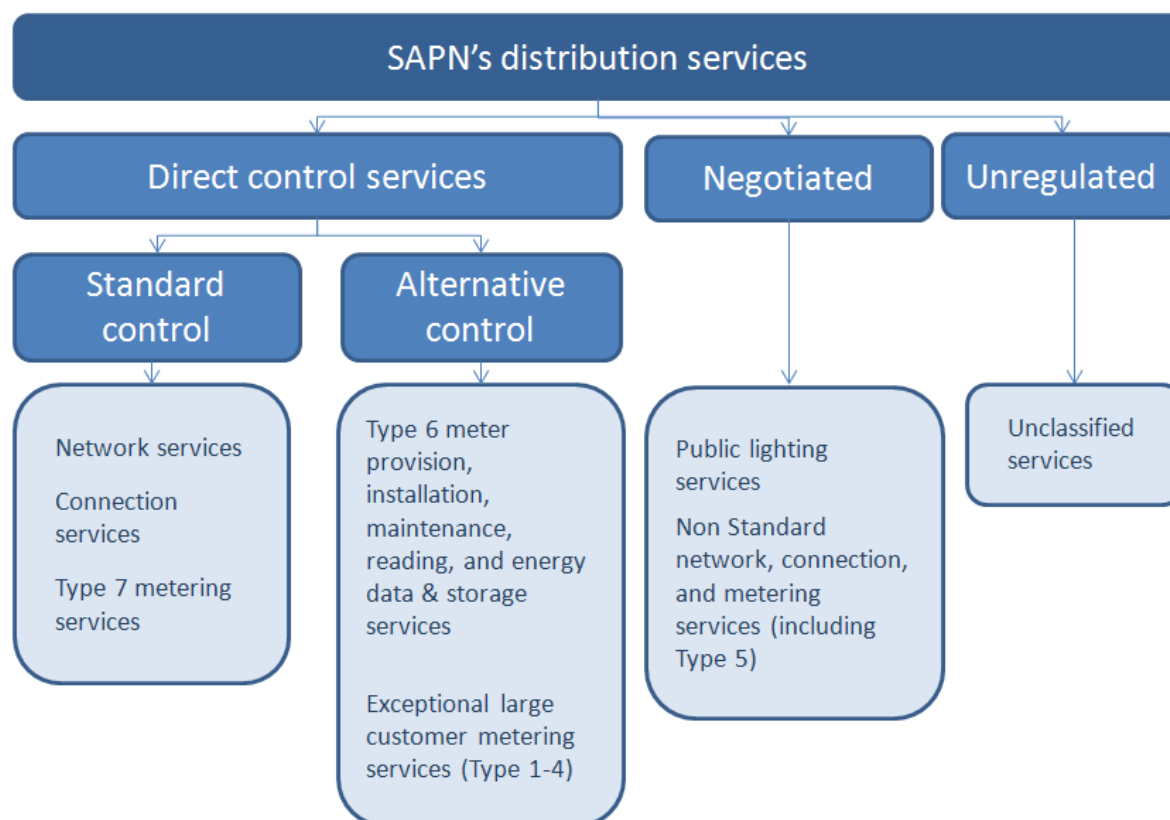
1.1 AER's preliminary approach

Our proposed classification of SA Power Networks' distribution services is set out in figure 3.

²⁴ NER, Chapter 10, definition of 'distribution service'.

²⁵ NER, Chapter 6, part B.

Figure 3: Our proposed classification of SAPN's distribution services



Source: AER

Standard network services typically form a majority of distribution services. This group of services forms the core of what an electricity distributor does and includes activities like constructing and maintaining the network. SA Power Networks provides standard network services under a restrictive licence issued by the Essential Service Commission of South Australia (ESCOSA), which precludes other service providers. As it would be inefficient to have multiple providers of network services, competition for these services would not be in the interests of consumers. When competition is absent, we apply the most prescriptive form of regulation— direct control.

Because SA Power Networks' standard network services are used by most (if not all) of its customers, it is appropriate for SA Power Networks to recover these costs from all customers. We therefore classify network services as standard control.

Similar to network services, basic connection services are provided on a routine basis and are currently classified as standard control. SA Power Networks is the only provider of basic connection services. A basic (or standard) connection is a connection or an alteration which involves minimal or no augmentation (no extension or upgrade) of SA Power Networks' distribution network. This is different to non-basic connection services which require an augmentation. It is provided on a 'standard' or routine basis. Because basic connection services are not contestable in South Australia, we consider that these services should be classified as standard control.

Sitting between direct control and unregulated services, is the negotiated service classification. This is a light handed approach to regulation. Negotiated service prices are set by negotiation between the parties according to a framework set out in the rules. We are available to arbitrate if negotiations stall.

This classification typically relies on both parties possessing sufficient market power for effective negotiations. We consider a number of SA Power Networks' distribution services would benefit from this classification. For example, metering services for type 1 to 4 meters (for large electricity consumers and those with remotely read meters) are fully contestable. That is, SA Power Networks does not have an exclusive right to provide these metering services. We consider consumers have sufficient market power, within contestable markets, to negotiate efficient prices for these services. Likewise, we consider other distribution services where customers possess similar countervailing market power such as public lighting, non-standard network and connection services, should be classified as negotiated services.

In summary, with the exception of a number of standard type 6 metering related services, our proposed approach to service classification is to maintain the existing classifications for distribution services applied in the 2010–15 regulatory control period. This is because we consider there is insufficient evidence to suggest that a change in classification is clearly more appropriate.

1.2 AER's assessment approach

We follow a three stage assessment process when classifying distribution services. Figure 2 above outlines this process:

1. We must first satisfy ourselves that a service is a 'distribution service' (step 1 in figure 2). The rules define a distribution service as a service provided by means of, or in connection with, a distribution system.²⁶ A distribution system is a 'distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system'.²⁷
2. We then consider whether economic regulation of the service is appropriate for the distribution service (step 2 in figure 2). Where we do not think economic regulation is appropriate, because of the presence of competition, we will not classify the service. If there is little or no competition in relation to a service, we consider whether to classify the service as either a direct control or negotiated distribution service.²⁸
3. Where we consider a service should be classified as direct control service, we further classify it as either a standard control or alternative control service (step 3 in figure 2).²⁹

When classifying distribution services, we must do so in accordance with the rules. We must also have regard to the 'form of regulation factors'. The rules applicable to classification, and the form of regulation factors, are set out in appendix A.

The rules also specify that for services regulated previously, we must act on the basis that unless a different classification is clearly more appropriate:

- there should be no departure from a previous classification (if the services have been previously classified); and
- if there has been no previous classification, our classification should be consistent with the previous regulatory approach.³⁰

²⁶ See Chapter 10 of the rules for the definition of 'distribution service'. Connection assets alone do not constitute a distribution system.

²⁷ Ibid.

²⁸ NER, clause 6.2.1, NEL section 2F.

²⁹ NER, clause 6.2.2.

The rules also allow us to group distribution services. We may classify a class of activities rather than the specific activities that form part of the service. This provides SA Power Networks with flexibility to alter the exact specification (but not the nature) of a service during the regulatory control period. Where we make a single classification for the group of services, it applies to each service in the group.

We intend to group distribution services provided by SA Power Networks as:

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

We consider that the groups of services above are distribution services. They each provide services by means of, or in connection with, a distribution service.³¹ Appendix B sets out our classification of SA Power Networks' distribution services for the 2015–2020 regulatory control period.

1.3 Reasons for AER's preliminary position

Generally, classification is an assessment of the extent to which distributors provide services in a competitive market. We also consider whether all customers benefit from the service or whether customers request specific services for their direct benefit.

The majority of distributors' services are provided in a monopoly environment. Often this is because of strict legislative licensing provisions permitting only the licensed distributor to perform the service. Most of these services benefit all customers. Therefore, distributors share the costs of these services across the customer base as general network charges. Such services include standard network services and basic connection services.³²

We intend to classify services for maintaining, reading and repairing type 6 meters³³ as alternative control services.³⁴ A distributor generally provides these services for the benefit of an identifiable customer and there is potential to further develop competition for these services. In these instances, we consider it appropriate that the distributor levy service specific charges to the customer receiving these services.³⁵ This provides transparency in the real cost of the service and allows for a 'user pays' system where appropriate. This approach is consistent with the current classification of these services and is supported by stakeholder submissions on the notice for the initiation of the F&A process³⁶.

³⁰ NER, clauses 6.2.1(d) and 6.2.2(d).

³¹ NER, chapter 10, definition of 'distribution service'. We consider that each service group is provided 'in connection' with or 'in conjunction' with a distribution system. We also rely on *Ergon Energy Corporation Ltd v Australian Energy Regulator* [2012] FCA 393.

³² A Basic (or standard) connection is a connection or an alteration which involves minimal or no augmentation (no extension or upgrade) of SAPN's distribution network.

³³ See section 1.3.3 for an explanation of different types of meters.

³⁴ Also includes maintaining and reading of type 1 to 4 meters installed prior to 1 July 2000 for legacy reasons.

³⁵ In the current 2010–15 regulatory control period, the AER separated type 6 meters from other SAPN assets and established a regulatory asset base for these meters. The metering charges for individual customers are derived based on the return on this regulatory asset base and the on-going expenditures required to maintain these meters.

³⁶ Origin Energy, submission to the Queensland and South Australian Framework and Approach for the period 2015-2020, dated 31 July 2013.

We intend to classify public lighting services as negotiated services. Public lighting services include the provision, construction and maintenance of street lighting (or street lighting use of system service), lighting equipment rate services and energy only services. Public lighting services are contestable in South Australia as customers do not have to use SA Power Networks to provide, operate and maintain their street lighting assets.³⁷ We consider this provides some countervailing power to customers in negotiating the provision of these services. This approach is supported by two major customers of public lighting services (local councils and the Transport Services Division).

We intend to classify a range of non-standard network services as negotiated services. Some of these services are competitively available, such as:

- non-standard metering services – small and large customers, type 1 to 7
- stand-by and temporary supply services
- embedded generation services
- provision of a copy of various codes
- provision of reactive power
- investigation and testing services
- transportation of electricity not consumed in the distribution system
- provision of high load escorts
- provision of measuring devices
- provision of protection systems
- provision of television or radio interference investigations where the interference is not caused by the distribution system
- provision of information to parties not related to connection enquires.

Other services are generally provided at the request of, or for the benefit of, specific customers, such as:

- connection services with higher quality and reliability standards or in excess of SA Power Networks' service or plant rates
- non-basic connections, new and upgraded connection points – where financial contribution to an extension or augmentation is required
- asset relocation, temporary disconnection and temporary line insulation services
- application for an account or new supply
- provision of old billing data
- after hours reconnection

³⁷ SAPN are responsible for the ongoing maintenance work of its own public lighting assets. Therefore maintenance services for these public lighting assets are not contestable.

- reconnection due to users fault
- disconnection services provided to the retailer or user
- asset allocation and identification services
- transportation of electricity to users connected to the distribution system adjacent to the transmission system
- repair of equipment damaged by user or third party
- provision of pole attachments, ducts or conduits (excluding telecommunication services)
- costs incurred as a result of a customer not complying with the standard connection and supply contract or other obligation
- additional costs incurred due to the actions or inaction of a customer or their agent.

Either due to the contestable nature or greater elasticity of demand for these services compared to the core distribution services, we consider that a less intrusive regulatory approach is appropriate. The above services are consistent with SA Power Networks' negotiated services classification for the 2010–2015 regulatory period.

The classification of each of the service groups is addressed in detail below.

1.3.1 Network services

We consider standard network services predominately relate to a distributor's services provided over its shared distribution network to service all customers connected to it. Network services are an important group of distribution services. These services are associated with the safe and reliable conveyance, and controlling the conveyance, of electricity through the network.³⁸ Consumers use or rely on these network services on a daily basis. Examples of standard network services include:

- maintenance of substations, poles, lines and cables
- pole and other asset repairs and replacements
- planning, designing and operating the network for electricity distribution purposes.

Standard network services do not include metering services and non-basic connection services.³⁹

We intend to classify standard network services as direct control services and further, as standard control services. Our proposed approach is consistent with the current classification of these services.

SA Power Networks holds an electricity distribution licence.⁴⁰ This licence is the only distribution licence currently issued for South Australia. As the sole holder of the licence SA Power Networks has the obligation to operate, maintain and protect its supply network. To ensure safe, reliable and economic supply of electricity to users, only SA Power Networks can provide network services which

³⁸ NER, chapter 10, definition of 'network services'.

³⁹ Network services exclude metering data services. However, the AER considers a distributor's use of meter data for managing and planning the network, for example, is included in network services. A basic (or standard) connection is a connection or an alteration which involves minimal or no augmentation (no extension or upgrade) of SAPN's distribution network. This is different from non- basic connection services which require an augmentation.

⁴⁰ The licence is issued by the Essential Service Commission of South Australia. A copy of the licence is available on ESCOSA's website at www.escosa.sa.gov.au/electricity-overview/licensing/distribution-licences.aspx.

relate to the safe and reliable conveyance, and controlling the conveyance, of electricity through the distribution network. Additionally, consumers cannot source network services from external providers.

We consider these arrangements together effectively amount to an absolute regulatory barrier preventing third parties from providing these network services.⁴¹ Therefore, we consider that the market for network services is closed to competition from third parties. Because of the current legislative and licensing arrangements, SA Power Networks possesses complete market power for the provision of network services.⁴² We therefore intend to classify network services as direct control services.

We must further classify direct control services as standard control or alternative control services.⁴³ We intend to retain the current classification of network services as standard control services as:

- there is little, if any, potential to develop competition in the market for network services. The absence of competition is due to SA Power Networks holding the only licence to provide network services in the SA.
- there would be no material effect on administrative costs to us, SA Power Networks, users or potential users. This is because classifying network services as standard control services is consistent with the current regulatory approach.
- we currently classify network services in SA and all other NEM jurisdictions as standard control services.
- SA Power Networks provides network services through its shared network and cannot directly attribute the costs of these services to individual customers.

For the above reasons, we consider it should continue to classify network services as standard control services.

1.3.2 Connection services

In the current 2010–2015 regulatory control period, SA Power Networks offers two types of connection services for basic and non-basic connections. A basic connection is a connection or an alteration which involves minimal or no augmentation (no extension or upgrade) of SA Power Networks' distribution network. This is different from non-basic connection services which require an augmentation. Basic connection services are currently classified as standard control services, while non-basic connection services are grouped under the non-standard network services group and are classified as negotiated services.

Basic connection services

We intend to classify basic connection services as standard control services.

Basic connection services are currently provided to the following groups of customers:

- residential customers (no extension or upgrade required)⁴⁴

⁴¹ NEL, s. 2F(a).

⁴² NEL, s. 2F(d).

⁴³ NER, clause 6.2.2(c).

⁴⁴ NER, chapter 5A, A1.

- small business customers up to a capacity of less than 63 amps per phase
- small embedded generators (e.g. customers who wish to install solar PV panels on their premises) with a generating capacity of up to 10kVA for a single phase connection and up to 30kVA for a three phase connection.

Similar to network services, SA Power Networks currently provides basic connection services on a 'standard' or routine basis. For example, a new residential property owner having their house connected to the network with minimal or no augmentation. This type of connection request is common to anyone wanting to connect to the network to use electricity.

We consider the current classification of standard control for basic connection services is appropriate because:

- there is little, if any, prospect for competition in the market for basic connection services. That is, we are not aware of any government initiatives to introduce contestability for connection services in the coming regulatory control period. Therefore, our classification will not influence the potential for competition.
- there would be no material effect on administrative costs to us, SA Power Networks, users or potential users. This is because classifying connection services as standard control services is consistent with the current regulatory approach.
- we classify standard connection services in Queensland, South Australia and Tasmania as standard control services.⁴⁵ In Victoria, we classify standard connection services as alternative control services.⁴⁶
- we note that the nature of connection services is such that in most instances, the customer requesting the service will benefit from the provision of that service. As such, the costs are directly attributable to identifiable customers. To protect the broader customer base from incurring additional costs for services of no benefit to them, connections which require augmentation or significant alteration to the distribution network (as opposed to basic connection service where no such costs are required) need the requesting customer to make a capital contribution. This is discussed in the non-basic connection services section below.

For the above reasons, we consider no change to the current classification of standard control for basic connection services is justified.

Non-basic connection services

We intend to classify non-basic connection services as negotiated services.

Unlike basic connection services, non-basic connection services are connection services that require an augmentation to the network. As noted above, in most instances, connection services will only benefit the customer requesting that service. To protect the broader customer base from incurring additional costs arising from an individual customer's request for a non-standard service which is of no benefit to them, non-standard connections require the requesting customer to make a capital contribution.

⁴⁵ AER, *Final decision, Queensland distribution determination 2010-11 to 2014-15*, May 2010, p. 8; AER, *Final decision, South Australia distribution determination 2010-11 to 2014-15*, May 2012, p. 7; AER, *Final distribution determination Aurora Energy Pty Ltd 2012-13 to 2016-17*, April 2012, p. 9.

⁴⁶ AER, *Final decision, Victorian DNSPs distribution determination 2011-2015*, October 2010, p. 14.

Non-standard connection services are currently classified as negotiated services. The price for these services is set by individual negotiation between the requesting customer and SA Power Networks. We consider it is appropriate to continue to regulate non-standard connection services under a negotiate-arbitrate framework. This is because the administrative costs for users, SA Power Networks and us to impose price regulation are significant. Forecasting the costs and magnitude of this type of connection service is complex, as these aspects will depend on the circumstances of individual customers requesting these services (for example, the location and distance from the closest network infrastructure, and the connection characteristics desired by the customer). 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.⁴⁷

In classifying connection services, other than the factors set out in the rules,⁴⁸ we have considered chapter 5A of the rules and its connection charge guideline (connection guideline).⁴⁹ The purpose of chapter 5A and the connection guideline is to provide a framework and charging principles for new connections or connection alterations.⁵⁰ We are mindful of classifying SA Power Networks' connection services in a way that supports the operation of chapter 5A and the connection guideline.

Under chapter 5A and the connection guideline, connection services classified as standard control services will be charged according to our decision on the form of control (for example, a price cap or revenue cap). Chapter 5A and the connection guideline also provide that for connection services a distributor may seek a capital contribution from the customer toward the cost of the connection service. This means a distributor may only seek a capital contribution from a customer when the incremental cost of the connection service exceeds the estimated incremental revenue expected to be derived from the connection service. Put simply, if the customer's connection cost exceeds the revenues that will be paid by that customer over time, then the customer will be asked to make a contribution to the connection costs.

We consider classifying non-standard connection service as negotiated services is consistent with the operation of chapter 5A and the connection guideline. Under this classification non-standard connection services will be regulated under a negotiate–arbitrate framework. The framework is set out in chapter 5A of the rules and the connection guideline provides guidance on the practical implementation of the framework. Further, we have approved a Connection Policy document for SA Power Networks' distribution network effective from January 2013. We consider this will provide further assistance for South Australian consumers to better understand where additional contributions may be required.

For the above reasons, we consider no change to the current classification for non-basic connection services is justified.

1.3.3 Metering services

All electricity customers have a meter that measures the amount of electricity they use.⁵¹ However, not all customers have the same type of meter. There are different types of meters which each measure electricity usage in different ways.

⁴⁷ AER, *SA 2010–15 F&A Preliminary position*, pp. 29–31.

⁴⁸ NER, clauses 6.2.1 and 6.2.2.

⁴⁹ AER, *Connection charge guidelines for electricity retail customers, under Chapter 5A of the National Electricity Rules*, June 2012.

⁵⁰ AER, *Connection charge guidelines for electricity retail customers, under Chapter 5A of the National Electricity Rules*, June 2012, p. 29.

⁵¹ All connections to the network must have a metering installation (NER, clause 7.3.1A(a)).

Type 1 to 4 meters are generally provided to large customers who consume greater than 160 megawatt hours (MWh) of electricity per annum. Clause 7.2.3(a)(1) of the rules provides that provision of these types of meters is contestable.

However, SA Power Networks is the monopoly provider of type 5 and 6 meters.⁵² Distributors provide these default meter types to households and other small consumption users. Type 6 meters simply record total electricity usage over a period of time. Type 5 meters can record both electricity usage and the time of use.⁵³

SA Power Networks currently offers the following metering services for different types of meters:

- provision and installation of a Type 5 to 7 meter
- provision and installation of a Type 1 to 4 meter
- energy data services (except the quarterly meter read service)
- unscheduled meter reading – non-chargeable
- metering investigation
- maintaining and repairing meters and load control equipment
- scheduled meter reading
- exceptional large customer metering services (types 1 to 4 installed prior to 1 July 2000)
- meter testing at the request of the customer.

South Australia is the first jurisdiction where we unbundled metering services for type 6 meters. In the 2010–2015 regulatory control period, the provision of metering services such as maintenance, repair and scheduled reading for type 6 meters is unbundled from other metering services such as energy data and storage services and metering investigation.

Customers seek interval meters because they offer more frequent information about usage which allows them to better manage their electricity use.

We currently classify the metering services provided by SA Power Networks for type 1 to 4 meters as negotiated services. However, two exceptional cases of large customer metering services (customers with type 1 to 4 meters installed prior to 1 June 2000) are classified as alternative control services for legacy reasons.⁵⁴ Type 5 meter services are currently classified as negotiated services.

SA Power Networks is the monopoly provider of type 7 metering services, which are special unmetered connections (for example, public lighting connections).⁵⁵ The metering service for type 7 meters is classified as standard control.

In summary, currently SA Power Networks' metering services are:

- type 1 to 5 – negotiated services

⁵² SAPN is the 'responsible person' for type 5, 6, and 7 metering installations (NER, clause 7.2.3(a)(2)).

⁵³ Interval meters record electricity usage every 30 minutes.

⁵⁴ AER, *Final framework and approach paper ETSA Utilities 2010–15*, p. 10.

⁵⁵ NER, clause 7.2.3(a)(2).

- avoidable type 6 metering services – alternative control services
- fixed component of type 6 metering service – standard control services
- type 7 – standard control services.

We propose changing the above classification for the fixed component of the type 6 metering service to alternative control. Further, we have separated the current type 6 'meter provision and installation services' into two separate alternative control services. Our proposed approach to classifying metering services is set out in Table 3.

Table 3: AER's proposed approach to classifying metering services

AER's proposed approach		
Metering services	Type 7 metering	Standard control
	Type 6 energy data services (except the quarterly meter read service)	Alternative control
	Unscheduled meter reading – non-chargeable	
	Metering investigation – type 6	
	Maintaining and repairing meters and load control equipment – type 6	
	Type 6 meter installation	
	Type 6 meter provision	
	Scheduled meter reading – type 6	
	Exceptional large customer metering services (types 1-4 installed prior to 1 July 2000)	
	Meter testing at the request of the customer	Negotiated

Source: AER

Our reasons follow.

Type 1 to 4 metering services

Type 1 to 4 metering services are contestable in South Australia.⁵⁶ For this reason, we intend to classify these services as negotiated services. This is consistent with the current regulatory approach.

We note that there are two exceptional cases of type 1 to 4 meters where the provision of metering services has been classified as a direct control service, and further as an alternative control service in the current 2010–2015 regulatory control period for legacy reasons. These exceptional cases relate to:

- customers consuming between 160 and 750 MWh per annum who have type 1 to 4 metering installations provided prior to 1 July 2000

⁵⁶ Industrial and large customers may use types 1 to 4 meters. These meters are already open to competition and are not regulated by the AER (NER, clauses 7.2.3(a)(2) and 7.3.1.A(a)).

- customers consuming more than 750 MWh per annum who have type 1 to 4 metering installations provided prior to 1 July 2005.

The circumstances for these customers have not changed and we intend to maintain the current classification for these services.

Type 5 metering services

We intend to classify type 5 metering services as negotiated services. This is consistent with the current regulatory approach.

Under the rules, type 5 metering provision services are non-contestable. However, the metering services provided by SA Power Networks associated with the 'non-standard' features of type 5 meters compared to type 6 meters (such as the ability to measure the time of use of energy) in some degree competes with the provision of type 4 metering services from alternative providers. For this reason, we do not consider that a direct form of price control is warranted. Accordingly, we intend to classify type 5 metering services in a manner consistent with the current regulatory approach and as negotiated services.

Type 6 metering services

We consider it appropriate to apply the following classification to type 6 metering services as set out in Table 4 below.

Table 4: Proposed approach to classifying type 6 metering services

AER's proposed approach	
Service	Proposed classification
Type 6 meter installation – this includes on site connection of a meter at a customer's premises	Alternative control
Type 6 meter provision – this refers to the capital cost of purchasing the metering equipment to be installed	Alternative control
Type 6 energy data services (except the quarterly meter read service)	Alternative control
Unscheduled meter reading – non-chargeable	Alternative control
Metering investigation	Alternative control
Scheduled meter reading	Alternative control
Maintaining and repairing meters and load control equipment	Alternative control
Meter testing at the request of the customer	Negotiated

Our reasons follow.

We intend to separately classify individual type 6 metering services as direct control services.

We consider it necessary to classify type 6 metering services as direct control services because, due to current legislative requirements,⁵⁷ there are no real substitutes for type 6 metering services.⁵⁸ This barrier⁵⁹ provides SA Power Networks with significant market power in providing these services.⁶⁰ In fact, SA Power Networks is currently the sole provider of type 6 meters in South Australia.⁶¹ Type 6 metering services are currently subject to a direct form of control in South Australia and other NEM jurisdictions.

Given that we have classified type 6 metering services as direct control services, we must further classify these services as standard or alternative control services.⁶² We consider type 6 metering services should be alternative control services because there is the potential for competition for these services. We recognise that SA Power Networks is currently the monopoly provider of type 6 metering services.⁶³ However, we consider that an alternative control classification will enhance competition should contestability for these services change.⁶⁴ If charges for these services were bundled in distribution charges, any future changes in contestability may be far less effective. Additionally, our proposed approach is consistent with the AEMC's draft report for its Power of Choice Review. The AEMC's recommendations included that:

- the current metering arrangements need reform to provide investment in better metering technology and provide customer choice
- metering costs should be unbundled from shared network charges.⁶⁵

The AEMC also released a Power of Choice supplementary paper on metering services, exploring the arrangements necessary to implement its recommendations.⁶⁶ The AEMC recommended that metering provision be contestable and open to competition among approved service providers. Further, it stated that customers should be able to choose a metering service provider.⁶⁷ The AEMC designed its recommendations to promote the investment in, and use of, advanced metering infrastructure ('smart' metering). It considers there will be demand management benefits for customers, retailers and distributors in using advanced metering infrastructure.⁶⁸

We consider that keeping type 6 metering services unbundled from other standard control services will enhance competition for providers of type 4 meters. It will enable alternative providers to compete with SA Power Networks on both price and non-price aspects. Additionally:

- there would be little administrative cost to us, SA Power Networks, users or potential users. This is because classifying type 6 metering services as alternative control services is largely consistent with the current regulatory approach.

⁵⁷ NER, clause 7.2.3.

⁵⁸ NEL, ss. 2F(e) and (f).

⁵⁹ NEL, s. 2F(a).

⁶⁰ NEL, s. 2F(d).

⁶¹ SAPN, *Response to query on classification of metering services*, 21 January 2013, p. 1.

⁶² NER, clause 6.2.2(c).

⁶³ NER, clause 7.2.3(a)(2) provides that a distributor, as the local network service provider, is the responsible person for type 6 meter installations.

⁶⁴ NER, clauses 6.2.2(c)(1) and (c)(6).

⁶⁵ AEMC, *Draft report, Power of choice - giving consumers options in the way they use electricity*, 6 September 2012, pp. 47-56.

⁶⁶ AEMC, *Power of choice review draft report, Supplementary paper, Principles for metering arrangements in the NEM to promote installation of DSP metering technology*, 6 September 2012 (AEMC, *Power of choice metering paper*, September 2012).

⁶⁷ AEMC, *Power of choice metering paper*, September 2012, p. 4.

⁶⁸ AEMC, *Power of choice metering paper*, September 2012, pp. 7-9.

- there is some variation in the classification of metering services across NEM jurisdictions. However, type 6 metering services in Tasmania are alternative control services.⁶⁹ We are also proposing that some type 5 and 6 metering services in NSW be classified as alternative control services.⁷⁰
- we consider that an alternative control classification for some type 6 metering services is appropriate, as customers will only pay for services they receive.
- another relevant factor⁷¹ we considered is the potential to create a more transparent and accurate way of providing customers with costing information. Directly attributing costs under an alternative control classification allows customers to make informed choices on meter provision, maintenance and reading services.

We have received many submissions supporting our proposed position to classify type 6 metering services as alternative control services in the NSW framework and approach process. Generally, stakeholders submitted that unbundling type 6 metering services from network services would allow for more transparent costing. This in turn would create favourable conditions to develop competition.⁷²

Our proposed approach retains the current classification for most type 6 metering services except:

- Type 6 energy data services (except the quarterly meter read service)
- Unscheduled meter reading – non-chargeable
- Metering investigation.

We propose to reclassify these services from standard control to alternative control. This provides customers with more transparent costing information for these services. It will assist them to make informed choices should future rule changes allow a third party other than SA Power Networks to provide these services. Another change we propose to make to the classification of type 6 metering services is to further break down the meter provision service into two services; meter installation service and meter provision service. The former covers the on site connection of a meter at a customer's premises. The latter covers the capital cost of purchasing the metering equipment to be installed. This approach results in a more transparent and accurate way of providing customers with costing information.

A meter testing service provided at the request of a customer is contestable and therefore it is appropriate to classify this as a negotiated service.

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. It is also likely to promote the development of competition in the small customer metering market.

⁶⁹ AER, *Final Decision, South Australia Draft distribution determination 2010-11 to 2014-15*, 25 November 2009, p. xi; AER *Final F&A decision for Aurora Energy Pty Ltd*, November 2012, pp. 15, 24 and 68-69.

⁷⁰ AER, *Stage 1 Final F&A paper for NSW Distributors*, March 2013, p. 14.

⁷¹ NER, clause 6.2.2(c)(6).

⁷² AER, *Stage 1 Framework and approach paper Ausgrid, Endeavour Energy and Essential Energy*, March 2013, pp. 26-27.

Non-standard type 6 import and export meters

We intend to classify non-standard type 6 import and export metering services as negotiated services. This is consistent with the current regulatory approach.

Non-standard type 6 'import and export' meters for solar photovoltaic (PV) installations are currently classified as negotiated services. Pursuant to clause 7.3.1(a)(7) of the rules, an import and export (I/E) meter must be installed for all generators connected to the distribution network, including small PV installations. Despite the PV I/E metering service being classified as a negotiated service, it is not contestable as SA Power Networks is the only service provider. Under the South Australia Electricity Metering Code (Metering Code), which regulates metering arrangements in South Australia, read with clause 7.2 of the rules, SA Power Networks is the only "responsible person" permitted to provide this type of meter service in South Australia.

Potentially the PV I/E metering service may be classified as alternative control service given the service is not contestable. This would introduce price or revenue regulation for the service. The advantages of this approach are that it would introduce more scrutiny of the costs of providing the service, and more transparent pricing. However, setting a price has the following disadvantages:

- there is an increase in administrative costs of SA Power Networks and us
- it introduces forecasting risks, this is particularly the case for future PV penetration
- it is inflexible and does not take into account technological advances, that is, cost reductions due to advances in metering technology may not be realised as the price is fixed from the on-set.

Also, we are not aware of any evidence that suggests that the current classification is failing customers, however this does not mean that issues do not exist.

On balance, our preliminary position is to maintain the current negotiated service classification for non-standard type 6 import and export meters for SA. We seek submissions from stakeholders as to whether a different classification is clearly more appropriate.

Type 7 metering services

We intend to classify type 7 metering services as direct control and further, as standard control services.

A type 7 meter does not measure the flow of electricity. Examples include streetlights or traffic lights. Distributors charge customers, usually councils or government agencies, for unmetered connections by estimating usage using standard data. For example, the distributor estimates streetlight usage using the total time the lights were on, the number of lights in operation and the light bulb wattage. As only SA Power Networks estimates usage, only it can bill customers.

Similar to type 6 metering services, services for type 7 meters could be unbundled. However, the avoidable component involved in providing type 7 metering services is likely to be minimal (and relate only to energy data services). We do not consider there is a net benefit from unbundling charges for these services from the distribution use of system tariff. For this reason, we are likely to classify type 7 metering services as standard control services, consistent with the regulatory approach in the current regulatory control period.

1.3.4 Public lighting

We intend to classify public lighting services as negotiated services.

South Australia is currently the only jurisdiction where public lighting services are negotiated. However, this classification is consistent with the classification set by the previous jurisdictional regulator, ESCOSA.

Public lighting services includes provision, construction and maintenance of street lighting (or street lighting use of system service), lighting equipment rate services and energy only services. South Australian customers (local councils, Transport Service Division) are not required to ask SA Power Networks to provide, operate and maintain their street lighting assets. Customers have the option of providing (and owning), operating and maintaining their own lights, and effectively avoiding all SA Power Networks' physical public lighting services (by using an 'energy only' service), and/or only employing SA Power Networks to replace failed light bulbs in their lights.

We consider these options could provide some countervailing power to customers and place some competitive constraint on SA Power Networks' pricing of public lighting services. This view is supported by submissions from two of the major customers of public lighting services, local councils (represented by the Local Government Association of SA) and the Transport Service Division of the South Australian Department of Planning, Transport and Infrastructure. Both expressed their preference for public lighting to continue to be classified as a negotiated service.⁷³ A number of other stakeholders also expressed similar views and support for retaining the current classification for public lighting services in their submission to our initial notice for the SA F&A.⁷⁴

For these reasons, we consider there is no clear reason to change the current classification of public lighting services.

1.3.5 Non-standard network services

We intend to classify non-standard network services⁷⁵ as negotiated services.

The prices for non-standard network services are negotiated between SA Power Networks and customers. SA Power Networks also publishes on its website an indicative price list for these services.

Some of the non-standard network services are competitively available, such as:

- non-standard metering services – small and large customers, types 1 to 7
- stand-by and temporary supply services
- embedded generation services
- provision of a copy of various codes
- provision of reactive power

⁷³ Department of Planning, Transport and Infrastructure, *submission to the South Australian Framework and Approach for the regulatory control period commencing 1 July 2015*, dated 25 July 2013, and the Local Government Association of South Australia, *submission to the South Australian Framework and Approach paper*, dated 29 July 2013.

⁷⁴ Submissions can be found at www.aer.gov.au/node/20941.

⁷⁵ These services are listed in sections B.7 to B.16 of appendix B.

- investigation and testing services
- transportation of electricity not consumed in the distribution system
- provision of high load escorts
- provision of measuring devices
- provision of protection systems
- provision of television or radio interference investigations where not caused by the distribution system
- provision of information to parties not related to connection enquiries.

Other non-standard network services are generally provided at the request of, or for the benefit of, specific customers, including:

- connection services with higher quality and reliability standards or in excess of SA Power Networks' service or plant rates
- non-basic connections, new and upgraded connection points – where financial contribution to an extension or augmentation is required
- asset relocation, temporary disconnection and temporary line insulation services
- application for an account or new supply
- provision of old billing data
- after hours reconnection
- reconnection due to users fault
- disconnection services provided to the retailer or user
- asset allocation and identification services
- transportation of electricity to users connected to the distribution system adjacent to the transmission system
- repair of equipment damaged by user or third party
- provision of pole attachments, ducts or conduits (excluding telecommunication services)
- costs incurred as a result of a customer not complying with the standard connection and supply contract or other obligation
- additional costs incurred due to the actions or inaction of a customer or their agent.

Given the contestable nature of the first group of non-standard network services⁷⁶, we intend to classify them as negotiated services.

⁷⁶ Those listed as competitively available on p. 32 (dot points 1-12).

The remaining services⁷⁷ generally involve working on, or in relation to, parts of SA Power Networks' distribution network. Therefore, as a licensed monopoly provider, only SA Power Networks can undertake these services. We consider that, similar to network services, there is a regulatory barrier preventing any party other than SA Power Networks providing these services. However, these services are currently classified as negotiated services because⁷⁸:

- the classification is consistent with the regulatory approach adopted by the previous jurisdictional regulator ESCOSA
- the costs of these services can be attributed to an individual customer. This is because of the specific nature of the services only benefiting an individual or small sub-set of customers
- the elasticity of demand and the substitutable nature of these services are greater for these services compared to the core distribution services
- although the current legislation does not allow these services to be contestable, the potential for development of competition exists if the barrier is relaxed
- potential administrative costs in introducing price or revenue regulation are likely to be significant for customers, SA Power Networks and us compared to potential benefits. This is because it is difficult to establish the costs and volume forecasts required for price or revenue regulation due to infrequent and non-standard nature of these services
- The circumstances surrounding the provision of these services have not changed since we classified these services as negotiated services. Having regard to the potential administrative costs in introducing price or revenue regulation, on balance, we consider that there is insufficient evidence to overcome the presumption in favour of the previous classification for the non-standard network services under clauses 6.2.1(d) and 6.2.2(d) of the rules. For this reason, we intend to maintain the current classification of negotiated services for non-standard network services.

1.4 Conclusion

In summary, we intend to group and classify the SA Power Networks' distribution services as set out in Table 5 and 6.

We seek submissions on our preliminary position on the classification of SA Power Networks' distribution services. In particular, whether non-standard type 6 import and export meter services should remain classified as negotiated services.

⁷⁷ Those listed as 'other non-standard services' on p. 33 (dot points 1-14).

⁷⁸ AER, *Final framework and approach ETSA Utilities 2010–2015 regulatory control period*, pp. 28-32.

Table 5: Proposed classification of SAPN's direct control and negotiated distribution services

Service category	Direct control	Negotiated distribution
Network services	Network services at mandated standard	Network services at higher (or lower) than mandated standard
Connection services	<p>Connection services at mandated standard</p> <p>New or upgraded connection services (to the extent the user is not required to make a financial contribution)</p>	<p>Connection services at higher (or lower) than mandated standard</p> <p>New or upgraded connection services (to the extent that the user is required to make a financial contribution)</p>
Metering services	<p>Small customer standard meter provision and energy data services (type 6 metering installation services and type 6 meter provision services)</p> <p>Unmetered metering services (type 7 metering installations)</p> <p>Two 'exceptional cases' of large customer metering services (type 1 to 4 meter provision services), being:</p> <ul style="list-style-type: none"> - customers consuming between 160 and 750 MWh per annum who have types 1 to 4 metering installations provided prior to 1 July 2000, and - customers consuming more than 750 MWh per annum who have types 1 to 4 metering installations provided prior to 1 July 2005. 	<p>Small customer non-standard meter provision and energy data services (type 1 to 5 metering installations, and type 5 to 7 metering installations containing a meter different to the type SAPN would usually install)</p> <p>Small customer special meter reads (including monthly reads)</p> <p>Large customer meter provision and energy data services (type 1 to 4 metering installations)</p>
Public lighting services	Nil	<p>Provision, operation and maintenance of public lighting assets</p> <p>Lamp replacement</p> <p>'Energy only' services</p>
Non-standard network services	Nil	<p>Remaining services listed in appendix B as negotiated distribution services, which includes:</p> <ul style="list-style-type: none"> - provision of stand-by or temporary supply - asset relocations - temporary disconnections - provision of copies of various codes - embedded generation services

Source: AER

Table 6: Proposed classification of SAPN's direct control services into 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	Unmetered metering services (type 7 metering installations)	<p>Standard small customer metering services and energy data services (type 6 metering provision and installations)</p> <p>Two 'exceptional cases' of large customer metering services (type 1 to 4 meter provision services), being:</p> <ul style="list-style-type: none"> - customers consuming between 160 and 750 MWh per annum who have types 1 to 4 metering installations provided prior to 1 July 2000 - customers consuming more than 750 MWh per annum who have types 1 to 4 metering installations provided prior to 1 July 2005.
Public lighting services	Nil	Nil
Non-standard network services	Nil	Nil

Source: AER

2 Control mechanisms

This attachment sets out our proposed control mechanisms to apply to SA Power Network's direct control services for the 2015–20 regulatory control period. This attachment also sets out our proposed approach on the formulae to give effect to the control mechanisms for direct control services.

Our distribution determination must impose controls over the prices (and/or revenues) of direct control services. This paper states our preliminary positions, together with our reasons, on the form(s) of the control mechanism(s) to apply to direct control services in the determination for the 2015–2020 regulatory control period. We classify direct control services as standard control services or alternative control services. Different control mechanisms may apply to each of these classifications, or to different services within the same classification.

We can only approve the control mechanisms in SA Power Networks' regulatory proposal if they are the same as those set out in the F&A. We can also only approve the proposed formulae to give effect to the control mechanisms in SA Power Network's regulatory proposal if they are the same as the formulae set out in the F&A, unless we consider that unforeseen circumstances justify departing from the formulae set out in this paper.⁷⁹

2.1 AER's preliminary position

Our preliminary position is to apply the following forms of control in the 2015–2020 regulatory control period:

- Revenue cap — for services we have classified as standard control services.
- Price cap for individual services — for services we have classified as alternative control services.

2.2 AER's assessment approach

Our consideration of the control mechanisms for direct control services consists of three parts:

- the control mechanism⁸⁰
- the basis of the control mechanism⁸¹
- the formulae to give effect to the control mechanisms.

Clause 6.2.5(b) of the rules sets out the control mechanisms that may apply to both standard and alternative control services:

- a schedule of fixed prices

A schedule of fixed prices specifies a price for every service provided by a distributor. The specified prices are escalated annually by inflation, the X factor⁸² and applicable adjustment

⁷⁹ NER, clause 6.12.3(c).

⁸⁰ NER, clause 6.2.5(b).

⁸¹ NER, clause 6.2.6(a).

⁸² The X factor for a particular year in the regulatory control period is the highest percentage increase a distributor can apply to the average DUOS tariff excluding inflation, pass throughs and any other adjustment factors. An X factor can be positive or negative. A positive X factor means the average tariff is increasing less than the rate of inflation, while a negative X factor indicates that average tariff is increasing faster than the rate of inflation.

factors.⁸³ Distributors comply with the constraint by submitting prices matching the schedule in the first year and then escalated prices in subsequent years.

- caps on the prices of individual services⁸⁴

Caps on the prices of individual services are the same as a schedule of fixed prices except that a distributor may set prices below the specified prices.

- caps on the revenue to be derived from a particular combination of services (revenue cap)

A revenue cap sets a maximum allowable revenue (MAR) for each year of the regulatory control period. Distributors must then recover revenue equal to or less than the MAR. Distributors comply with the constraint by forecasting sales for the next regulatory year and setting prices so the expected revenue is equal to or less than the MAR. At the end of each regulatory year, the distributor reports its actual revenues to us. We account for differences between the actual revenue recovered and the MAR in future years. This operation occurs through an 'overs and unders' account, whereby any over-recovery (under-recovery) is deducted from (added to) the MAR in future years.

- tariff basket price control (WAPC)

A WAPC is a cap on the average increase in prices from one year to the next. This allows prices for different services to adjust each year by different amounts. For example, some prices may rise while others may fall, subject to the overall WAPC constraint. A weighted average is used to reflect that services may be sold in different quantities. Therefore, a small increase in the price of a frequently provided service must be offset by a large decrease in the price of an infrequently provided service. Distributors comply with the constraint by setting prices so the change in the weighted average price is equal to or less than the CPI-X cap. Importantly, the WAPC places no cap on the revenue recovered by a distributor in any given year. That is, if revenue recovered under the WAPC is greater than (less than) the expected revenue, the distributor keeps (loses) that additional (shortfall) revenue.

- revenue yield control (average revenue cap)

An average revenue cap is a cap on the average revenue per unit of electricity sold that a distributor can recover. The cap is calculated by dividing the MAR by a particular unit (or units) of output, usually kilowatt hours (kWh). The distributor complies with the constraint by setting prices so the average revenue is equal to or less than the MAR per unit of output.

- a combination of any of the above (hybrid)

A hybrid control mechanism is any combination of the above mechanisms. Typically, hybrid approaches involve a proportion of revenue that is fixed and a proportion that varies according to pre-determined parameters, such as peak demand.

In considering our preliminary position, we have not considered a schedule of fixed prices or caps on the prices of individual standard control services. This is because we consider these direct price

⁸³ The applicable adjustment factor captures the revenue adjustments required to account for the outcome of various applicable schemes or pass throughs. For example, the 's-factor' adjustment will be included in the price calculation to capture the revenue impact based on the outcome of the STPIS.

⁸⁴ A price cap and a schedule of fixed prices are largely the same mechanism, with the only difference being that a price cap allows the distributors to charge below the allocated price on some or all of the services.

control mechanisms do not provide the level of flexibility within the regulatory control period for distributors to manage distribution use of service charges shared across the broad customer base. Consequently, our assessment is focussed on a revenue cap or WAPC.

2.2.1 Standard control services

In determining a control mechanism to apply to standard control services, we will have regard to the factors in clause 6.2.5(c) of the rules:

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

We propose to have regard to three other relevant factors which we consider are relevant to assessing the most appropriate control mechanism:

- revenue recovery
- price flexibility and stability
- incentives for demand side management.

The basis of the control mechanism for standard control services must be of the prospective CPI-X form or some incentive-based variant.⁸⁵

The following subsections outline our consideration of each of the above factors in determining the form of control for standard control services.

Need for efficient tariff structures

Appendix C outlines some high level considerations about the concept of efficient pricing structures. Broadly, we consider prices are efficient if they reflect the underlying cost of supplying distribution services and take into account customers' willingness to pay.

Efficient pricing is important for several reasons:

- where prices are cost reflective, allocative efficiency is maximised because consumers can compare the cost of providing the service to their needs and wants.⁸⁶

⁸⁵ NER, clause 6.2.6(a).

⁸⁶ Allocative efficiency is achieved when the value consumers place on a good or service (reflected in the price they are willing to pay) equals the cost of the resources used up in production. The condition required is that price equals marginal cost. When this condition is satisfied, total economic welfare is maximised.

- where prices are cost reflective, consumers and providers of demand side management face efficient incentives because they can take into account the cost of providing the service in decision making.
- cost reflective prices allow distributors to make efficient investment decisions. Consumers base consumption decisions on the cost of providing the service compared to their value of consumption and increases or decreases in demand signal the potential need for extra network capacity.

Administration costs

Where possible, a control mechanism should minimise the complexity and administrative burden for us, distributors and users.

Existing regulatory arrangements

We consider that consistency in regulatory arrangements across regulatory periods for similar services provided by a distributor is generally desirable.

Desirability of consistency between regulatory arrangements

We consider that consistency within and across jurisdictions for similar services is generally desirable.

Revenue recovery

We consider that a control mechanism should give distributors an opportunity to recover efficient costs. We also consider that a control mechanism should limit revenue recovery above such costs. Revenue recovery above efficient costs results in higher prices for consumers. Further, distributors' recovering additional revenue from price sensitive services through prices above marginal cost reduces allocative efficiency.

Pricing flexibility and stability

Price flexibility enables distributors to restructure existing prices and/or introduce charges for new services.

The stability and predictability of distribution network prices is important because it affects consumers' ability to manage bills and retailers' ability to manage risks incurred from changes to network prices.

Incentives for demand side management

Demand side management refers to the implementation of non-network solutions to avoid the need to build network infrastructure to meet increases in annual or peak demand.⁸⁷ We consider demand side management projects are efficient if the reduction in network expenditure is greater than the cost of implementing the project. Consumers benefit from efficient demand side management projects through reductions in total network costs.

⁸⁷ Peak demand is generally referred to as the maximum load on a section of the network over a very short time period.

2.2.2 Alternative control services

We must have regard to the factors listed in clause 6.2.5(d) of the rules in deciding on a control mechanism for alternative control services:

- the potential for the development of competition in the relevant market and how the control mechanism might influence that potential
- the possible effects of the control mechanism on administrative costs of the AER, the distributor and users or potential users
- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination
- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)
- any other relevant factor.

The control mechanism must have a basis stated in the distribution determination.⁸⁸ This may, but need not, utilise elements of Part C of chapter 6 of the rules with or without modification. For example, the control mechanism may, but need not, use a building block approach or incorporate a pass-through mechanism.⁸⁹

2.3 Reasons for AER's preliminary position

This section sets out the reasons for our preliminary position on the forms of control for the 2015–2020 regulatory control period regarding standard and alternative control services.

2.3.1 Standard control services

We consider that a revenue cap best meets the factors set out under clause 6.2.5(c) compared to the other available control mechanisms under clause 6.2.5(b) of the rules. We consider that a change from a WAPC, which applies in the current regulatory period, to a revenue cap will result in benefits to consumers through:

- a higher likelihood of revenue recovery at efficient cost
- lower administration costs
- incentives for efficient demand side management
- lower reliance on energy forecasts
- facilitation of the introduction of efficient prices and pricing structures through increased pricing flexibility
- we consider that the detriments of a revenue cap compared to a WAPC are able to be mitigated - within period pricing instability can be addressed through new modelling techniques and the application of tolerance limits. We also consider that the revenue caps' weak pricing incentives have little practical effect. Though not a factor in our considerations, we further note that the weak

⁸⁸ NER, clause 6.2.6(b).

⁸⁹ NER, clause 6.2.6(c).

pricing incentives may in any case be addressed through rule changes proposed by SCER for distribution network pricing arrangements.⁹⁰

Our consideration of these issues is provided below.

Need for efficient tariff structures

Revenue cap

We consider that by itself the revenue cap provides limited incentive for distributors to set efficient prices. That is, under a revenue cap, distributors' revenues are fixed over the regulatory control period. Distributors therefore maximise profits by decreasing costs. To decrease costs, distributors face an incentive to increase prices above marginal costs on price sensitive, high cost services. This results in reductions in demand for those services below efficient levels.

We consider that this incentive is unlikely to apply to, or give rise to inefficient pricing by SA Power Networks. We consider that the majority of SA Power Networks' variable costs are caused by augmentations and connections (where demand for connections is likely to be price insensitive) to the network. The incentive for distributors to decrease costs through pricing is therefore likely to result in higher prices for peak demand. This would require a shift towards peak energy and peak demand/capacity tariffs. In the current environment where tariffs largely consist of flat energy/capacity tariffs (as noted in appendix C) we consider that a shift towards peak energy/capacity prices will result in increases in pricing efficiency.

WAPC

Distributors under a WAPC can retain revenue recovered above the expected revenue calculated by us. Theoretically, this provides distributors with an incentive to set prices efficiently. That is, distributors are able to increase profit by reducing the price on price sensitive services towards marginal cost. This incentive arises because when a distributor reduces the price of any service(s) under the WAPC it is allowed to increase the price on another service(s). The distributor can therefore increase profit by simultaneously decreasing the price on price sensitive services and increasing the price on price insensitive services. This is because customers of price sensitive services are likely to respond to lower prices by using more of those services. The decrease in a distributor's revenue caused by it lowering prices is therefore offset by the increase in sales. Meanwhile, customers of price insensitive services are likely to respond to higher prices by using the same amount, or only slightly less, of those services.

We consider the WAPC's theoretical advantages have not eventuated in practice because they rely on assumptions that do not apply to electricity distributors. These assumptions include:

- distributors have the expertise, incentive, infrastructure and independence to set prices to maximise profit:
 - distributors must have the expertise to estimate the price sensitivity of different services (and components of services) and adjust prices accordingly
 - distributors objective in setting prices must be to maximise profit

⁹⁰ AEMC, *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, Consultation Paper*, 14 November 2013.

- distributors must have, or have the ability to install, the necessary metering technology to provide cost reflective tariffs
- distributors must be free from outside influence to set profit motivated prices.
- pass through of distribution costs to consumers:
 - Often retail charges do not reflect the underlying structure of network costs and changes in network prices are not passed through in full to consumers. This is especially the case where retail price regulation applies.
 - Distribution charges represent only one component of network charges. Where distributors have discretion to set transmission and other charges, which do not fall under the WAPC, these charges may be adjusted to impact network charges.
- Fully informed consumers:
 - Consumers must know of price changes when they happen. Particularly where retail price regulation exists many consumers do not see price changes until bills are received midway through the regulatory year.
 - Consumers must be capable of understanding and incentivised to respond to price signals. Where complicated price structures exist, such as inclining block tariffs,⁹¹ many consumers are not able to understand the price they are charged for electricity usage.

We consider that where these assumptions do not hold the WAPC does not provide an incentive to set efficient prices. For example, where the first assumption holds but the last two do not, the incentive to maximise profit remains but it does not result in an incentive to set efficient prices. Instead, distributors maximise profits by increasing prices on services expected to increase in quantity. Alternatively, where the first assumption does not hold distributors may be more likely to maintain previous pricing structures/levels regardless of their efficiency.

It is difficult to evaluate efficient pricing outcomes under the WAPC by SA Power Networks due to its recent introduction. However, in the recent Stage 1 NSW F&A we undertook extensive analysis of pricing outcomes under the WAPC in NSW and Victoria. We concluded that the WAPC has not provided an incentive for, or resulted in, increased pricing efficiency. Included in this analysis were the inefficiencies related to the widespread use of inclining block tariffs and the low utilisation of tariffs based on network cost drivers. Appendix C demonstrates that these features also apply to SA Power Network's current pricing.

The details of the analysis of efficient pricing under the WAPC are presented in in appendix C.

Administrative costs

We consider that there is generally little difference in administrative costs between control mechanisms under the building block framework. However, in the current context we consider that a revenue cap will reduce administrative costs to users and us due to consistency between regulatory arrangements. We are proposing the retention of a revenue cap in Queensland. NSW also will be under a revenue cap in the 2014–2019 regulatory control period and Tasmania is already operating

⁹¹ Under block tariff structures, distributors charge customers different prices for different levels of consumption at a given point of time. An inclining block tariff has charges increasing as consumption increases. Block tariffs are discussed in appendix C.

under a revenue cap. This consistency will lead to reduced administrative costs through standardisation of modelling approaches, incentive schemes and consultation requirements.

Existing regulatory arrangements

We consider that consistency across regulatory control periods is generally desirable. However, it is not primary to our consideration in this instance. We consider that desirability needs to be weighed against the other factors under clause 6.2.5(c) of the rules. We consider this is appropriate because consistency in and of itself has no direct effect on distributors, us or customers.

Desirability of consistency between regulatory arrangements

We consider that consistency between regulatory arrangements is generally desirable but is not primary to our consideration in this instance. Its desirability needs to be weighed against the other factors under clause 6.2.5(c). The outcomes under the other factors reveal outcomes that further the National Electricity Objective and are consistent with the revenue and pricing principles.

Revenue recovery

We consider that a revenue cap provides a high likelihood of efficient cost recovery. As a distributor's costs are largely fixed and unrelated to energy sales, for efficient cost recovery to occur revenue recovery should be largely fixed and unrelated to energy sales. This is the case under the revenue cap because revenue is fixed over the regulatory control period. Differences from forecast cost drivers, e.g. peak demand and customer numbers, may cause differences in distributors' costs. Where this occurs, variations from efficient cost recovery may result under the revenue cap. We have therefore considered adjustment mechanisms (hybrid control mechanisms) to the revenue cap for variations from forecast peak demand and customer numbers. Our consideration of hybrid control mechanisms is set out in the last part of this section.

We do not consider that a WAPC provides a high or even a reasonable likelihood of efficient cost recovery. Under the WAPC revenue varies with the volume of energy sales. We consider this provides an opportunity for distributors to recover revenue systematically above forecast. That is, under a WAPC distributors have the opportunity to recover revenue substantially above forecast revenue when actual quantities exceed forecast quantities, and to recover revenue close to forecast when actual quantities are below forecast quantities.

It is difficult to evaluate efficient cost recovery under the WAPC by SA Power Networks because of its recent introduction. However, in the NSW stage 1 F&A we conducted analysis of revenue recovery by NSW and Victorian distributors and found that distributors were able to recover revenue systematically above forecast.

Pricing flexibility and stability

Pricing flexibility

We consider that price flexibility for existing tariffs and tariff structures is primarily influenced by the side constraints and the pricing principles, not the form of control mechanism.

We consider that the revenue cap results in increased pricing flexibility in relation to the introduction of new tariffs and tariff structures. Under a revenue cap, to introduce a new tariff or tariff structure, distributors are required to submit reasonable forecasts for that tariff. As there is no revenue at risk

because revenue is fixed over the regulatory control period, the incentive to manipulate such forecasts is low. Conversely, under a WAPC, distributors submit reasonable estimates when introducing new tariffs or tariff structures. We assess these estimates rigorously as substantial revenue is at risk which can result in significant changes in profit for distributors. We consider that this will be of increasing importance under likely changes to the pricing principles proposed by SCER.

Pricing stability

We consider price instability can occur under all forms of control mechanisms. This is because the rules require various annual price adjustments regardless of the control mechanism.⁹²

We consider that there is increased likelihood of overall price instability within a regulatory control period under a revenue cap. That is, distributors must adjust prices during the regulatory control period to account for differences between forecast and actual sales volumes. We consider that tolerance limits and the design of the unders and overs account can limit price adjustments in any one year. For example, in Queensland in the current period we applied tolerance limits to the unders and overs account.⁹³ In Tasmania, we designed the unders and overs account as a rolling account with an estimate year to help smooth the price adjustments year on year.^{94,95} We also consider that incorporating forecast sales in forming the X-factors in the distribution determination will result in lower balances in the unders and overs account.⁹⁶

We consider the WAPC can increase overall price stability within the regulatory control period compared to a revenue cap. However, we do not consider a WAPC is likely to lead to increased price stability or predictability for individual tariffs or customers. Under a WAPC distributors face an incentive to re-balance tariffs to maximise profit and this incentive may result in large changes to tariffs within the regulatory control period.

We consider that the WAPC can result in greater price instability across regulatory control periods compared to the revenue cap. This issue is particularly pronounced if a trend of falling volumes has set in throughout the regulatory control period, prompting a large upward adjustment in the X-factors (and hence prices) for the next regulatory control period under the WAPC. In contrast, the volume forecasts are updated annually under a revenue cap. This would mean that prices would rise gradually over the regulatory period (rather than jump up at the end of the period) if a trend of falling demand was evident.

Incentives for demand side management

We consider a revenue cap provides an incentive to undertake efficient demand side management. Conversely, a WAPC provides a disincentive to undertake efficient demand side management.

Under a revenue cap we fix distributors' revenue over the regulatory control period. Distributors can therefore increase profits by reducing total cost. This creates an incentive for distributors to undertake demand side management projects that reduce total costs i.e. any demand side management project

⁹² These include cost pass throughs, jurisdictional scheme obligations, tribunal decisions and transmission prices passed on to the distributors from the transmission network service providers.

⁹³ Queensland distribution determination 2010–11 to 2014–15, Appendix D, May 2010.

⁹⁴ Final Distribution Determination Aurora Energy Pty Ltd 2012–13 to 2016–17, pp. 20–23, April 2012.

⁹⁵ This approach means that instead of waiting two years before incorporating the under or over recovery into prices, an estimate (based on nine months of data) is used in the calculation of the under or over recovery. This will reduce the likelihood of undesirable price shocks by smoothing the under and over recovery using more updated and accurate estimated and forecast data in the middle year.

⁹⁶ Currently under revenue caps the X-factors perform an adjustment of prices from revenue year on year without taking into account forecasted changes in customer numbers, energy sales and demand.

where the reduction in network expenditure is greater than the cost of implementing the demand side management. We consider this provides an efficient incentive for distributors to undertake efficient demand side management projects.

Under a WAPC distributors' revenues are directly linked to the actual volumes of energy sales and demand. This means that when a distributor undertakes a demand side management project that reduces energy sales or demand its revenue will decrease. Therefore, for a distributor to increase profits by undertaking a demand side management project, the reduction in augmentation expenditure would have to be greater than the cost of implementing the project plus the reduction in revenue from lower sales volumes. This creates a strong disincentive to undertake efficient demand side management projects as they often result in significant revenue decreases.

Hybrid form of control

We consider that higher administrative costs to distributors and us under a hybrid revenue cap outweigh its potential benefits.

There are many formulations for designing a hybrid form of control mechanism. We have considered a hybrid revenue cap where revenue is adjusted within the regulatory period to adjust for deviations from forecast cost drivers i.e. customer numbers and peak demand. This design enables distributors' revenues to align more closely to the cost drivers compared with a revenue cap. However, it may be difficult to develop an effective revenue function under a hybrid revenue cap. Furthermore, under the hybrid revenue cap we must recalculate the distributors' maximum allowable revenue each year. This would involve substantial administrative costs to distributors and us throughout the regulatory control period. Additionally, because a large proportion of distributors' costs are fixed rather than variable such adjustments may only result in small adjustments to distributors' maximum allowable revenues. For these reasons, the Independent Pricing and Regulatory Tribunal (NSW) moved away from a hybrid revenue cap to a revenue cap in the 1999–2004 distribution determination.⁹⁷ Other regulators (Queensland Competition Authority and the Office of the Tasmanian Economic Regulator) also noted the difficulties and complexities involved in developing and applying a hybrid revenue cap.⁹⁸

2.3.2 Formulae for standard control mechanism

We are required to set out our proposed approach to the formulae that give effect to the control mechanisms for standard control services in the F&A.⁹⁹ We must include the formulae in our final F&A in our distribution determination, unless we consider that unforeseen circumstances justify departing from the formulae as set out in the F&A.¹⁰⁰

Below is a preliminary formulae to apply to standard control services. We consider that the formula gives effect to the revenue cap.

$$(1) \quad MAR_t = \sum_{i=1}^n \sum_{j=1}^m P_{ij}^t q_{ij}^{t*} \quad i=1,\dots,n \text{ and } j=1,\dots,m \text{ and } t=1,\dots,5$$

$$(2) \quad MAR_t = AR_t + I_t + T_t + B_t$$

⁹⁷ IPART, *Form of Economic Regulation for NSW Electricity Network Charges: Discussion Paper 48*, August 2001, p. 10.
⁹⁸ QCA, *Final Determination – Regulation of Electricity Distribution*, May 2005, p. 30; OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices*, September 2003, p. 99.
⁹⁹ NER, clause 6.8.1(b)(2)(ii).
¹⁰⁰ NER, clause 6.12.3(c1).

$$(3) AR_t = AR_{t-1}(1 + CPI_t)(1 - X_t)$$

Where:

MAR_t is the maximum allowable revenue in year t.

p_{ij}^t is the price of component i of tariff j in year t.

q_{ij}^{*t} is the forecast quantity of component i of tariff j in year t.

AR_t is the annual smoothed revenue requirement in the Post Tax Revenue Model for year t.

I_t is the sum of incentive scheme adjustments in year t. To be decided upon in the final decision.

T_t is the sum of transitional adjustments in year t. Likely to incorporate but not limited to adjustments from the transitional regulatory control period. To be decided upon in the final decision.

B_t is the sum of annual adjustment factors in year t. Likely to incorporate but not limited to adjustments for the overs and unders account. To be decided upon in the final decision.

CPI_t is the percentage increase in the consumer price index. To be decided upon in the final decision.

X_t is the X-factor in year t. To be decided upon in the final decision.

2.3.3 Alternative control services

In our 2010 distribution determination, the variable components of the type 6 metering services (type 6 metering services) were the only services deemed to be alternative control services during the 2010–15 regulatory control period. We applied a weighted average price form of control to these services.

Our preliminary position is to apply a price cap for each individual alternative control type 6 metering services.

The difference between the price cap and the existing WAPC in the current regulatory control period is that the WAPC allows some flexibility for the service provider to implement a different price path for individual services under the tariff basket, while a price cap offers no such flexibility. This means the price path over the regulatory control period is fixed for each individual service. The advantage of this approach is that it provides a more transparent and predictable price path for customers compared to the weighted average approach. It will also reduce the likelihood of cross subsidisation between different type 6 metering services that may occur when adjusting the relative price between the services.

Our preliminary position is based on the following considerations under clause 6.2.5(d) of the rules:

- a price cap is one of the control mechanisms listed in clause 6.2.5(b) of the rules that can be applied in the next regulatory control period¹⁰¹
- we consider that a price cap promotes accurate price signals to the market through cost-reflective prices
- we consider that competition for alternative control services is limited at this point in time. However, where the development of competition is possible, the transparent and cost reflective nature of prices under the price cap will enable competitors to assess prices and make informed market entry decisions.
- we consider the administrative cost involved in switching from a weighted average price cap for a basket of services to a price cap for individual service is negligible because there will be no change to current reporting and modelling requirements
- in the current regulatory control period SA Power Networks applied the same price path for all services under the type 6 metering services basket, except for metering exit fees, which are escalated based on CPI. This means that the price and revenue outcome for the current regulatory control period is largely the same as if a price cap for individual services were applied. For this reason, we consider a price cap is consistent with the outcome under the current arrangement.

2.3.4 Formulae for alternative control mechanism

Below is a preliminary formulae to apply to alternative control services, which we propose to remain classified as alternative control services. We consider that the formula gives effect to the cap on the prices of individual services.

$$\bar{p}_i^t \geq p_i^t \quad i=1,\dots,n \text{ and } t=1,2,3,4$$

$$\bar{p}_i^t = \bar{p}_i^{t-1}(1 + CPI_t)(1 - X_i^t) + A_i^t$$

Where:

\bar{p}_i^t is the cap on the price of service i in year t

p_i^t is the price of service i in year t

CPI_t is the percentage increase in the consumer price index. To be decided upon in the final decision.

X_i^t is the X-factor for service i in year t. To be decided upon in the final decision.

A_i^t is an adjustment factor. Likely to include, but not limited to adjustments for residual charges when customers choose to replace assets before the end of their economic life.

¹⁰¹ NER, clause 6.2.5(b)(3).

3 Incentive schemes

This attachment sets out our preliminary position on the application of a range of incentive schemes to SA Power Networks for the next regulatory control period. At a high level, our preliminary position is to apply the:

- service target performance incentive scheme
- efficiency benefit sharing scheme
- capital expenditure sharing scheme
- demand management incentive scheme.

3.1 Service target performance incentive scheme

This section sets out our proposed approach and reasons for applying the service target performance incentive scheme (STPIS) to SA Power Networks in the next regulatory control period.

Our national distribution STPIS¹⁰² provides a financial incentive to distributors to maintain and improve service performance. The STPIS aims to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributors' incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the NEO.

The STPIS operates as part of the building block determination and contains two mechanisms:

- The service standards factor (s-factor) adjustment to the annual revenue allowance for standard control services rewards (or penalises) distributors for improved (or diminished) service compared to predetermined targets. Targets relate to service parameters pertaining to reliability and quality of supply, and customer service.
- A guaranteed service level (GSL) component composed of direct payments to customers¹⁰³ experiencing service below a predetermined level.¹⁰⁴

While the mechanics of how the STPIS will operate are outlined in our national distribution STPIS, we must set out key aspects specific to each distributor in the next regulatory control period at the determination stage, including:

- the maximum revenue at risk under the STPIS
- how the distributor's network will be segmented
- the applicable parameters for the s-factor adjustment of annual revenue across customer service, reliability and quality of supply components
- performance targets for the applicable parameters in each network segment

¹⁰² AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009.

¹⁰³ Except where a jurisdictional electricity GSL requirement applies.

¹⁰⁴ Service level is assessed (unless we determine otherwise) with respect to parameters pertaining to the frequency and duration of interruptions; and time taken for streetlight repair, new connections and publication of notices for planned interruptions.

- the criteria for certain events to be excluded from the calculation of annual performance and performance targets
- incentive rates determining the relative importance of measured performance (against targets) across applicable parameters in each network segment.

Distributors can propose to vary the application of the STPIS in their regulatory proposal.¹⁰⁵ We can accept or reject the proposed variation in our determination. Each applicable year we will calculate a distributor's s-factor based on its service performance in the previous year against targets, subject to the revenue at risk limit. Our national STPIS includes a banking mechanism, allowing distributors to propose delaying a portion of the revenue increment or decrement for one year to limit price volatility for customers.¹⁰⁶ A distributor proposing a delay must provide in writing its reasons and justification for believing that the delay will result in reduced price variations to customers.

Our national STPIS currently applies to SA Power Networks. SA Power Networks is currently subject to financial penalty or reward of ± 3 per cent through an s-factor adjustment to revenue. However, jurisdictional GSL arrangements do apply.¹⁰⁷

3.1.1 AER's preliminary position

Our preliminary position is to continue to apply the national STPIS to SA Power Networks in the next regulatory control period. Our proposed approach to applying the national STPIS in the next regulatory control period will be to:

- set revenue at risk for each distributor within the range ± 5 per cent
- segment the network according to our interpretation of the Standing Committee on National Regulatory Reporting Requirements (SCONRRR) feeder categories (CBD, urban, short rural and long rural)
- set applicable reliability of supply (system average interruption duration index or SAIDI and system average interruption frequency index or SAIFI) and customer service (telephone answering) parameters
- set performance targets based on the distributors' average performance over the past five regulatory years
- apply the methodology indicated in the national STPIS for excluding specific events from the calculation of annual performance and performance targets
- apply the methodology and value of customer reliability (VCR) values as indicated in our national STPIS to the calculation of incentive rates.

We will not apply the GSL component as SA Power Networks is subject to a jurisdictional GSL scheme.¹⁰⁸

¹⁰⁵ AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009, clause 2.2.

¹⁰⁶ AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009, clauses 2.5(d) and (e).

¹⁰⁷ AER, *Final framework and approach paper, application of schemes, ETSA Utilities 2010–15*, November 2008, p. 60.

¹⁰⁸ ESCOSA, *Electricity Distribution Code*, clause 1.1.4. A copy of this code can be found at www.escosa.sa.gov.au/library/130131-ElectricityDistributionCode-EDC10.pdf

We are aware of policy reviews indicating the need to reform the STPIS. The AEMC recently conducted a review of distribution reliability frameworks in the NEM.¹⁰⁹ AEMO is currently conducting analysis on how willing consumers are to pay for improvements in network reliability.¹¹⁰ We consider there is inadequate time to review our national STPIS to incorporate the findings of these reviews before finalising our determination for SA Power Networks.

3.1.2 AER's assessment approach

The rules require us to have regard to several factors in developing and implementing a STPIS for SA Power Networks.¹¹¹ These include:

- Jurisdictional obligations
 - consulting with the authorities responsible for the administration of relevant jurisdictional electricity legislation
 - ensuring that service standards and service targets (including GSL) set by the scheme do not put at risk the distributor's ability to comply with relevant service standards and service targets (including GSL) specified in jurisdictional electricity legislation and any regulatory obligations or requirements to which the distributor is subject.
- Benefits to consumers
 - the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any penalty or reward under the scheme
 - the willingness of the customer to pay for improved performance in the delivery of services.
- Balanced incentives:
 - the past performance of the distribution network
 - any other incentives available to the distributor under the rules or the relevant distribution determination
 - the need to ensure that the incentives are sufficient to offset any financial incentives the distributor may have to reduce costs at the expense of service levels
 - the possible effects of the schemes on incentives for the implementation of non-network alternatives.

Our approach and reasons for developing the STPIS are contained in our final decision for the national distribution STPIS.¹¹²

3.1.3 Reasons for AER's preliminary position

Our reasons for applying the STPIS to SA Power Networks in the next regulatory control period are set out below.

¹⁰⁹ AEMC, *Review on national framework for distribution reliability*, 27 September 2013.

¹¹⁰ AEMO, *Value of customer reliability issues paper*, 11 March 2013; AEMC, *Advice on linking the reliability standard and reliability settings with VCR*, October 2013.

¹¹¹ NER, clause 6.6.2(b).

¹¹² AER, *Final decision: Electricity distribution network service providers Service target performance incentive scheme*, 1 November 2009.

Jurisdictional obligations

In SA, ESCOSA administers and monitors compliance with the distribution licence conditions set out in the Electricity Distribution Code. As required by the rules, we will consult with the ESCOSA and the Department for Manufacturing, Innovation, Trade, Resources and Energy (DMITRE) as jurisdictional authorities, on the implementation of the STPIS¹¹³ before finalising our distribution determination.

Our proposed approach to applying the STPIS in SA intends to not compromise the distributor's ability to comply with jurisdictional licence obligations or create duplication by:

- not setting service performance targets lower than the minimum service requirements in the licence conditions; and
- not applying the GSL component of our national STPIS while ESCOSA's guaranteed customer service arrangements remain in place.

Benefits to consumers

We are mindful of the potential impact of the STPIS on consumers. Under the rules, we must consider customers' willingness to pay for improved service performance so benefits to consumers are sufficient to warrant any penalty or reward under the STPIS.¹¹⁴

Under the STPIS, the distributors' financial penalty or reward in each year of the regulatory control period is the change in its annual revenue allowance after the s-factor adjustment. Economic analysis of the value consumers place on improved service performance is an important input to the administration of the scheme. Value of customer reliability (VCR) studies estimate how willing customers are to pay for improved service reliability as a monetary amount per unit of unserved energy during a supply interruption. As outlined in our national STPIS, we will use VCR estimates at different stages of our annual s-factor calculation to:

- set the incentive rates for each reliability of supply parameter; and
- weight reliability of supply performance across different segments of the network.

The VCR estimates in our national STPIS are taken from studies conducted for VENCORP and ESCOSA.¹¹⁵ The distributors may propose an alternative VCR estimate, supported by details of the calculation methodology and research, in their regulatory proposals.

The AEMC recently conducted a review of distribution reliability outcomes and standards in the NEM, proposing a more significant role for the STPIS.¹¹⁶ The Australian Energy Market Operator (AEMO) is currently reviewing current approaches to estimating VCR and will propose new VCR estimates in March 2014.

We intend to undertake a review of our national STPIS once these studies are complete. Any change to the STPIS would be subject to the distribution consultation procedures in the rules.¹¹⁷ We consider there is insufficient time to conduct a comprehensive review of the STPIS before SA Power Networks

¹¹³ NER, clause 6.6.2(b)(1).

¹¹⁴ NER, clause 6.6.2(b)(3)(vi).

¹¹⁵ Charles River Associates, *Assessment of the Value of Consumer Reliability (VCR)* - Report prepared for VENCORP, Melbourne 2002; KPMG, *Consumer Preferences for Electricity Service Standards*, 2003.

¹¹⁶ AEMC, *Draft report: Review of distribution reliability outcomes and standards*, 28 November 2012.

¹¹⁷ NER, Part G.

submits its proposal for the next regulatory control period in October 2014. Therefore our preliminary approach is to apply the national STPIS in its current form and monitor ongoing work.

Balanced incentives

We administer our incentive schemes within a regulatory control period to align distributor incentives with the NEO. In implementing the STPIS we need to be aware of both the operational integrity of the scheme itself and how it interacts with our other incentive schemes.

Distributor incentives under the STPIS

How we measure actual service performance and set performance targets can significantly impact how well the STPIS meets its stated objectives.

The rules require us to consider past performance of the distributor's network in developing and implementing the STPIS.¹¹⁸ Our preferred approach is to base performance targets on the distributors' average performance over the past five regulatory years.¹¹⁹ Using an average calculated over multiple years instead of applying performance targets based solely on the most recent regulatory year limits the distributors' incentive to underperform in the final year of a regulatory control period to make future targets less onerous.

Our national STPIS limits variability in penalties and rewards caused by circumstances outside the distributors' control. We exclude interruptions to supply deemed to be outside the major event day boundary from both the calculation of performance targets and measured service performance.

Our national STPIS recognises differences across and within distribution networks. Measured performance and performance targets are specific to each segment of a distributor's network.

Interactions with our other incentive schemes

In applying the STPIS we must consider any other incentives available to the distributor under the rules or relevant distribution determination.¹²⁰ In SA, the STPIS will interact with our expenditure and demand management incentive schemes.

The EBSS provides distributors with an incentive to reduce operating costs. The STPIS counterbalances this incentive by discouraging cost efficiencies arising through reduced service performance for customers. The s-factor adjustment of annual revenue depends on the distributor's actual service performance compared to predetermined targets. In accordance with the rules we must set incentive rates to offset any financial incentives the distributors may have to reduce costs at the expense of service levels.¹²¹

In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.¹²²

The CESS rewards distributors if actual capex is lower than the approved forecast amount for the regulatory year. Since our performance targets will reflect planned reliability improvements, any

¹¹⁸ NER, clause 6.6.2(b)(3)(iii).

¹¹⁹ Subject to any modifications required under clauses 3.2.1(a) and (b) of the national STPIS.

¹²⁰ NER, clause 6.6.2(b)(3)(iv).

¹²¹ NER, clause 6.6.2(b)(3)(v).

¹²² Included in the distributor's approved forecast capex for the subsequent period.

incentive a distributor may have to reduce capex by not achieving the planned performance outcome will be curtailed by the STPIS penalty.

The rules require us to consider the possible effects of the STPIS on the distributors' incentives to implement non-network alternatives to augmentation. The STPIS treats the reliability implications of network and non-network solutions symmetrically, neither encouraging nor discouraging non-network alternatives to augmentation.

We are aware of the perceived disincentive to implement demand-side alternatives to network augmentation created by reliability performance measures in the STPIS. Higher risk of failure to meet STPIS performance targets may act as a disincentive for non-network alternatives to network investment. One way to address this would be to exclude outages caused by non-network solutions from the calculation of actual performance. However, since network planning decisions are within the distributors' control, we consider this to be unnecessary.

3.2 Efficiency benefit sharing scheme

The efficiency benefit sharing scheme (EBSS) is intended to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and provide for a fair sharing of these between distributors and network users. Consumers benefit from improved efficiencies through lower regulated prices. This section sets out our preliminary position and reasons on how we intend to apply the EBSS to SA Power Networks in the next regulatory control period.

3.2.1 AER's preliminary approach

We propose applying our new EBSS¹²³ to SA Power Networks for the 2015–20 regulatory control period.

Our distribution determination for SA Power Networks for the next regulatory control period will specify how we will apply the EBSS.

3.2.2 AER's assessment approach

The EBSS must provide for a fair sharing between distributors and network users of opex efficiency gains and efficiency losses.¹²⁴ We must also have regard to the following factors in developing and implementing the EBSS:¹²⁵

- the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme
- the need to provide service providers with a continuous incentive to reduce opex
- the desirability of both rewarding service providers for efficiency gains and penalising service providers for efficiency losses
- any incentives that service providers may have to capitalise expenditure
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

¹²³ AER, *Efficiency benefit sharing scheme*, 29 November 2013.

¹²⁴ NER, clause 6.5.8(a).

¹²⁵ NER, clause 6.5.8(c).

3.2.3 Reasons for AER's preliminary approach

The current EBSS applies to SA Power Networks in their current regulatory control period.¹²⁶ As part of our Better Regulation program we consulted on and published the new EBSS, taking into account the requirements of the rules.

The new EBSS retains the same form as the current EBSS, and merges the distribution and transmission schemes. Changes in the new EBSS relate to the criteria for adjustments and exclusions under the scheme.¹²⁷ We also amended the scheme to provide flexibility to account for any adjustments made to base year opex to remove the impacts of one-off factors. The new EBSS also clarifies how we will determine the carryover period. These revisions affect how carryover amounts are calculated for future regulatory control periods.¹²⁸

In this section we set out why we propose to apply the new EBSS to SA Power Networks in the next regulatory control period.

3.2.4 Reasons for applying the EBSS in the next period

In developing the new EBSS we had regard to the requirements under the rules, as set out in the scheme and accompanying explanatory statement.¹²⁹ This reasoning extends to the factors we must have regard to in implementing the scheme.

The EBSS must provide for a fair sharing of efficiency gains and losses.¹³⁰ Under the scheme distributors and consumers receive a benefit where a distributor reduces its costs during a regulatory control period and both bear some of any increase in costs.

Under the EBSS, positive and negative carryovers reward and penalise distributors for efficiency gains and losses respectively.¹³¹ The EBSS provides a continuous incentive for distributors to achieve opex efficiencies throughout the subsequent period. This is because the distributor receives carryover payments so it retains any efficiency gains or losses it makes within the regulatory period for the length of the carryover period. This is regardless of the year in which it makes the gain or loss.¹³²

This continuous incentive to improve efficiency encourages efficient and timely opex throughout the regulatory control period, and reduces the incentive for a distributor to inflate opex in the expected base year. This provides an incentive for distributors to reveal their efficient opex which, in turn, allows us to better determine efficient opex forecasts for future regulatory control periods.

The EBSS also leads to a fair sharing of efficiency gains and losses between distributors and consumers.¹³³ For instance the combined effect of our forecasting approach and the EBSS is that opex efficiency gains or losses are shared approximately 30:70 between distributors and consumers. This means for a one dollar efficiency saving in opex the distributor keeps 30 cents of the benefit while consumers keep 70 cents of the benefit.

¹²⁶ AER, *Electricity distribution network service providers, efficiency benefit sharing scheme*, 26 June 2008.

¹²⁷ We will no longer allow for specific exclusions such as uncontrollable opex or for changes in opex due to unexpected increases or decreases in network growth. We may also exclude categories of opex not forecast using a single year revealed cost approach from the scheme on an ex post basis if doing so better achieves the requirements of the rules.

¹²⁸ AER, *Efficiency benefit sharing scheme for electricity network service providers*, 29 November 2013.

¹²⁹ AER, *Efficiency benefit sharing scheme for electricity network service providers*, 29 November 2013; AER, *Explanatory statement, Efficiency benefit sharing scheme for electricity network service providers*, 29 November 2013.

¹³⁰ NER, clause 6.5.8(a).

¹³¹ NER, clauses 6.5.8(c)(3) and 6.5.8(a).

¹³² NER, clause 6.5.8(c)(2).

¹³³ NER, clause 6.5.8(c)(1).

Example 1 shows how the EBSS operates. It illustrates how the benefits of a permanent efficiency improvement are shared approximately 30:70 between a network service provider and consumers.

Example 1 How the EBSS operates

Assume that in the first regulatory period, a distributor's forecast opex is \$100 million per annum (p.a.).

Assume that during this period the distributor delivers opex equal to the forecast for the first three years. Then, in the fourth year of the regulatory period, the distributor implements a more efficient business practice for maintaining its assets. As a result, the distributor will be able to deliver opex at \$95 million p.a. for the foreseeable future.

This efficiency improvement affects regulated revenues in two ways:

1. Through forecast opex. If we use the penultimate year of the regulatory period to forecast opex in the second regulatory period, the new forecast will be \$95 million p.a. If the efficiency improvement is permanent, all else being equal, forecast opex will also be expected to be \$95 million p.a. in future regulatory periods.
2. Through EBSS carryover amounts. The distributor receives additional carryover amounts so that it receives exactly six years of benefits from an efficiency improvement. Because the distributor has made an efficiency improvement of \$5 million p.a. in Year 4, to ensure it receives exactly six years of benefits, it will receive annual EBSS carryover amounts of \$5 million in the first four years (Years 6 to 9) of the second regulatory period.

As a result of these effects, the distributor will benefit from the efficiency improvement in Years 4 to 9. This is because the annual amount the distributor receives through the forecast opex and EBSS building blocks (\$100 million) is more than what it pays for opex (\$95 million) in each of these years.

Consumers benefit from Year 10 onwards after the EBSS carryover period has expired. This is because what consumers pay through the forecast opex and EBSS building blocks (\$95 million) is lower from Year 10 onwards.

Table 7 provides a more detailed illustration of how the benefits are shared between distributors and consumers over time.

(Example 1 continued)

Table 7 Example of how the EBSS operates

Year	Regulatory period 1					Regulatory period 2					Future
	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	100	100	100	100	100	95	95	95	95	95	95 p.a.
Actual (A_t)	100	100	100	95	95	95	95	95	95	95	95 p.a.
Underspend ($F_t - A_t = U_t$)	0	0	0	5	5	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	0	0	0	5	0	0*	0	0	0	0	0 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			0	0	0	0	0				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					5	5	5	5	5		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						5	5	5	5	0	0 p.a.
Benefits to distributor ($F_t - A_t + C_t$)	0	0	0	5	5	5	5	5	5	0	0 p.a.
Benefits to consumers ($F_t - (F_t + C_t)$)	0	0	0	0	0	0	0	0	0	5	5 p.a.
Discounted benefits to distributor**	0	0	0	5	4.7	4.5	4.2	4.0	3.7	0	0
Discounted benefits to consumers**	0	0	0	0	0	0	0	0	0	3.5	58.8***

Notes: * At the time of forecasting opex for the second regulatory period we do not know actual opex for year 5. Consequently this is not reflected in forecast opex for the second period. That means an underspend in year 6 will reflect any efficiency gains made in both year 5 and year 6. To ensure the carryover rewards for year 6 only reflect incremental efficiency gains for that year we subtract the incremental efficiency gain in year 5 from the total underspend. In the example above, $I_6 = U_6 - (U_5 - U_4)$.
 ** Assumes a real discount rate of 6 per cent.
 *** As a result of the efficiency improvement, forecast opex is \$5 million p.a. lower in nominal terms. The estimate of \$58.7m is the net present value of \$5 million p.a. delivered to consumers annually from year 11 onwards.

Table 8 sums the discounted benefits to distributors and consumers from the bottom two rows of Table 7. As illustrated below, the benefits of the efficiency improvement are shared approximately 30:70 in perpetuity between the distributor and consumers.

Table 8 Sharing of efficiency gains—Year 4 forecasting approach, with EBSS

	NPV of benefits of efficiency improvement	Percentage of total benefits
Benefits to distributor	\$26.1 million	30 per cent
Benefits to consumers	\$62.3 million	70 per cent
Total	\$88.3 million	100 per cent

In implementing the EBSS we must also have regard to any incentives distributors may have to capitalise expenditure.¹³⁴ Where opex incentives are balanced with capex incentives, a distributor does not have an incentive to favour opex over capex, or vice-versa. The CESS is a symmetric capex scheme with a 30 per cent incentive power. This is consistent with the incentive power for opex when we use an unadjusted base year approach in combination with an EBSS. During the subsequent period when the CESS and EBSS are applied, incentives will be relatively balanced, and distributors should not have an incentive to favour opex over capex or vice versa. The CESS is discussed further in section 3.3.

We must also consider the possible effects of implementing the EBSS on incentives for non-network alternatives:¹³⁵

- Expenditure on non-network alternatives generally takes the form of opex rather than capex. Successful non-network alternatives should result in the distributor spending less on capex than it otherwise would have. Non-network alternatives and demand management incentives are discussed further in section 3.4.
- When the CESS and EBSS both apply, a distributor has an incentive to implement a non-network alternative if the increase in opex is less than the corresponding decrease in capex. In this way the distributor will receive a net reward for implementing the non-network alternative.¹³⁶ This is because the rewards and penalties under the EBSS and CESS are balanced and symmetric. In the past where the EBSS operated without a CESS, we excluded expenditure on non-network alternatives when calculating rewards and penalties under the scheme. This was because distributors may otherwise receive a penalty for increasing opex without a corresponding reward for decreasing capex.¹³⁷

3.3 Capital expenditure sharing scheme

The CESS provides financial rewards for distributors whose capex becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiencies through lower regulated prices. This section sets out our proposed approach and reasons on how we intend to apply the CESS to SA Power Networks in the next regulatory control period.

The CESS approximates efficiency gains or efficiency losses by calculating the difference between forecast and actual capex. It shares these gains or losses between distributors and network users.

The CESS will work as follows:

- We calculate the cumulative underspend or overspend for the current regulatory control period in net present value terms.
- We apply the sharing ratio of 30 per cent to the cumulative underspend or overspend to work out what the distributor's share of the underspend or overspend should be.

¹³⁴ NER, clause 6.5.8(c)(4).

¹³⁵ NER, clause 6.5.8(c)(5).

¹³⁶ When the distributor spends more on opex it receives a 30 per cent penalty under the EBSS. However, when there is a corresponding decrease in capex the distributor receives a 30 per cent reward under the CESS. So where the decrease in capex is larger than the increase in opex the distributor receives a larger reward than penalty, a net reward.

¹³⁷ Without a CESS the reward for capex declines over the regulatory period. If an increase in opex corresponded with a decrease in capex, the off-setting benefit of the decrease in capex depends on the year in which it occurs.

We calculate the CESS payments taking into account the financing benefit or cost to the distributor of the underspends or overspends.¹³⁸ We can also make further adjustments to account for deferral of capex and ex post exclusions of capex from the RAB.

The CESS payments will be added or subtracted to the distributor's regulated revenue as a separate building block in the next regulatory control period.

Under the CESS a distributor retains 30 per cent of an underspend or overspend, while consumers retain 70 per cent of the underspend or overspend. This means that for a one dollar saving in capex the distributor keeps 30 cents of the benefit while consumers keep 70 cents of the benefit.

3.3.1 AER's preliminary position

Our preliminary position is to apply the CESS, as set out in our capex incentives guideline,¹³⁹ in the next regulatory control period to SA Power Networks.

3.3.2 AERs assessment approach

In deciding whether to apply a CESS to a distributor, and the nature and details of any CESS to apply to a distributor, we must:¹⁴⁰

- make that decision in a manner that contributes to the capex incentive objective¹⁴¹
- consider the CESS principles,¹⁴² capex objectives,¹⁴³ other incentive schemes, and where relevant the opex objectives, as they apply to the particular distributor, and the circumstances of the distributor.

Broadly speaking, the capex incentive objective is to ensure that only capex that meets the capex criteria enters the RAB used to set prices. Therefore, consumers only fund capex that is efficient and prudent.

3.3.3 Reasons for AER's preliminary position

We propose to apply the CESS to SA Power Networks in the next regulatory control period as we consider this will contribute to the capex incentive objective.

SA Power Networks are not currently subject to a CESS. As part of our Better Regulation program we consulted on and published version 1 of the capex incentives guideline which sets out the CESS.¹⁴⁴ The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.¹⁴⁵ We are also proposing to apply forecast depreciation, which is discussed further in attachment 5.

In developing the CESS we took into account the capex incentive objective, capex criteria, capex objectives, and CESS principles. We also developed the CESS to work alongside other incentive

¹³⁸ We calculate benefits as the benefits to the distributor of financing the underspend since the amount of the underspend can be put to some other income generating use during the period. Losses are similarly calculated as the financing cost to the distributor of the overspend.

¹³⁹ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5-10.

¹⁴⁰ NER, clause 6.5.8A(e).

¹⁴¹ NER, clause 6.5.8A(e).

¹⁴² NER, clause 6.5.8A(c).

¹⁴³ NER, clause 6.5.7(a).

¹⁴⁴ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5-10.

¹⁴⁵ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 11-12.

schemes that apply to distributors including the EBSS, STPIS, and DMIS—which SA Power Networks will be subject to in the next regulatory control period.

For capex, the sharing of underspends and overspends happens at the end of each regulatory period when we update a distributor's RAB to include new capex. If a distributor spent less than its approved forecast, it will benefit within that period. Consumers benefit at the end of the period when the RAB is updated to include less capex compared to if the business had spent the full amount of the capex forecast. This leads to lower prices in the future.

Without a CESS the incentive for a distributor to spend less than its capex forecast declines throughout the period.¹⁴⁶ Because of this a distributor may choose to spend capex earlier, or on capex when it may otherwise have spent on opex, or less on capex at the expense of service quality—even if it may not be efficient to do so.

With the CESS a distributor faces the same reward and penalty in each year of a regulatory control period for capex underspends or overspends. The CESS will provide distributors with an ex ante incentive to spend only efficient capex. Distributors that make efficiency gains will be rewarded through the CESS. Conversely, distributors that make efficiency losses will be penalised through the CESS. In this way, distributors will be more likely to incur only efficient capex when subject to a CESS, so any capex included in the RAB is more likely to reflect the capex criteria. In particular, if a distributor is subject to the CESS, its capex is more likely to be efficient and to reflect the costs of a prudent distributor.

When the CESS, EBSS and STPIS apply to distributors then incentives for opex, capex and service are balanced. This encourages distributors to make efficient decisions on when and what type of expenditure to incur, and to balance expenditure efficiencies with service quality.

3.4 Demand management incentive scheme

This section sets out our preliminary approach and reasons for applying a demand management incentive scheme (DMIS) to SA Power Networks in the next regulatory control period.¹⁴⁷

The usage patterns of geographically dispersed consumers determine how electrical power flows through a distribution network. Since consumers use energy in different ways, different network elements reach maximum utilisation levels at different times. Distributors have historically planned their network investment to provide sufficient capacity for these situations. As peak demand periods are typically brief and infrequent, network infrastructure often operates with significant latent capacity.

This underutilisation means that augmentation of network capacity may not always be the most efficient means of catering for increasing peak demand. Demand management refers to any effort by a distributor to lower or shift the demand for standard control services.¹⁴⁸ Demand management that effectively alleviates network utilisation during peak usage periods can be an economically efficient way of deferring the need for network augmentation.

¹⁴⁶ As the end of the regulatory period approaches, the time available for the distributor to retain any savings gets shorter. So the earlier a business incurs an underspend in the regulatory period, the greater its reward will be.

¹⁴⁷ The rules have since changed the name to 'Demand Management and Embedded Generation Connection Incentive Scheme' (DMEGCIS) to explicitly cover innovation with respect to the connection of embedded generation. Our current and proposed DMIS include embedded generation. We consider embedded generation to be one means of demand management, as it typically decreases demand for power drawn from a distribution network.

¹⁴⁸ For example, agreements between distributors and consumers to switch off loads at certain times and the connection of small-scale 'embedded' generation reducing the demand for power drawn from the distribution network.

The rules require us to develop and implement mechanisms to incentivise distributors to consider economically efficient alternatives to building more network.¹⁴⁹ To meet this requirement, and motivated by the need to improve SA Power Networks' capability in the demand management area, we implemented a DMIS in our revenue determination for the current regulatory period.

The current scheme includes a demand management innovation allowance (DMIA)¹⁵⁰. The DMIA is a capped allowance for distributors to investigate and conduct broad-based and/or peak demand management projects. It contains two parts:

- Part A adds an innovation allowance to each distributor's revenue each year of the regulatory control period. Distributors prepare annual reports on their expenditure under the DMIA¹⁵¹ in the previous year, which we then assess and approve under specific criteria.¹⁵²
- Part B compensates distributors for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A for distributors under a weighted average price cap. We applied this to SA Power Networks in the current regulatory control period. However, our preliminary position is that SA Power Networks will be subject to revenue cap form of control. Therefore, Part B is not relevant to SA Power Networks for the next regulatory control period.

3.4.1 AER's preliminary position

Our preliminary position is to continue applying the DMIA to SA Power Networks in the next regulatory control period.

We acknowledge the need to reform the existing demand management incentive arrangements in SA. SCER is currently considering a series of rule changes¹⁵³ proposed by the AEMC in its Power of Choice review¹⁵⁴ examining distributor incentives to pursue efficient alternatives to network augmentation. This will include new rules and principles guiding the design of a new DMIS. We intend to develop and implement a new DMIS during the next regulatory control period, depending on the progress of the rule change process. For these reasons, we propose not indicating the allowance cap in the F&A.

3.4.2 AER's assessment approach

The rules require us to have regard to several factors in developing and implementing a DMIS for SA Power Networks.¹⁵⁵ These are:

- Benefits to consumers
 - the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme
 - the willingness of customers or end users to pay for increases in costs resulting from implementing a DMIS.

¹⁴⁹ NER, clause 6.6.3(a).

¹⁵⁰ AER, *Demand management incentive scheme for Qld and SA*, 17 October 2008.

¹⁵¹ The DMIA excludes the costs of demand management initiatives approved in our determination for the 2009-14 period.

¹⁵² AER, *Demand management incentive scheme for Qld and SA*, 17 October 2008, p. 5.

¹⁵³ SCER, *Demand side participation – proposed rule changes*, 18 September 2013.

See: www.scer.gov.au/workstreams/energy-market-reform/demand-side-participation/proposed-rule-changes.

¹⁵⁴ AEMC, *Final report, Power of choice review – giving consumers choice in the way they use electricity*, 30 November 2012.

¹⁵⁵ NER, clause 6.6.3(b).

- Balanced incentives
 - the effect of a particular control mechanism (that is, price as distinct from revenue regulation) on a distributor's incentives to adopt or implement efficient non-network alternatives
 - the effect of classification of services on a distributor's incentive to adopt or implement efficient embedded generator connections
 - the extent the distributor is able to offer efficient pricing structures
 - the possible interactions between the DMIS and other incentive schemes.

3.4.3 Reasons for AER's preliminary position

This section outlines the reasons for our preliminary position to apply the DMIS to SA Power Networks in the next regulatory control period.

Benefits to consumers

Customers ultimately fund the DMIA adjustment to a distributor's annual revenue each year. As such, we are mindful of the potential impact of the DMIS on consumers. Under the rules, we must consider customers' willingness to pay for any higher costs resulting from the scheme so benefits to consumers are sufficient to warrant any penalty or reward.¹⁵⁶

We assess projects for which distributor's apply for DMIA funding under a specific set of criteria.¹⁵⁷ The DMIA aims to enhance distributors' knowledge and experience with non-network alternatives, therefore improving the consideration of demand management in future decision making. This means the benefits of any higher consumer prices directly caused by the scheme may not be revealed until later periods. Benefits include more efficient utilisation of existing network infrastructure and the deferral of costly network augmentation expenditure.

We expect the potential long-term efficiency gains resulting from improved distributor capability to undertake demand management initiatives to outweigh short-term price increases. Price impacts will be minimal as adjustments to annual revenue under the DMIA are capped at modest levels and apply only a 'use it or lose it' basis.

While studies¹⁵⁸ to date indicate that customers are supportive of demand management initiatives in principle, we know little about their willingness to pay. We consider our proposed application of the DMIS to be suitable in light of this limited information, given that the modest level of the DMIA means potential price increases will be minimal.

Balanced incentives

We administer our incentive schemes within a regulatory control period to align distributor incentives with the NEO. In implementing the DMIS, we need to be aware of how the scheme interacts within a distributor's overall incentive environment.

¹⁵⁶ NER, clause 6.6.3(b)(1).

¹⁵⁷ AER, *Demand management incentive scheme for Qld and SA*, 17 October 2008, p. 5.

¹⁵⁸ For example, Oakley Greenwood, *Valuing reliability in the national electricity market, final report*, March 2011. This report was prepared for AEMO.

Control mechanism and service classification

The rules require we have regard for how a distributor's control mechanism influences its incentives to adopt or implement efficient non-network alternatives to network augmentation.¹⁵⁹ We consider that a revenue cap form of control does not provide a disincentive for SA Power Networks to reduce the quantity of electricity as approved regulated revenues are not dependent on the quantity of electricity sold. That is, under a form of control where revenue is at least partially dependent on the quantity of electricity sold (for example, a price cap), a successful demand management program that causes a reduction in demand may result in less revenue for a distributor. A revenue cap avoids this scenario.

We are also required to consider the effect of service classification on a distributor's incentive to adopt or implement efficient embedded generator connections.¹⁶⁰ We consider our proposed application of the DMIS meets this requirement as SA Power Networks will be under a revenue cap in the next regulatory control period.

Distributor's ability to offer efficient pricing structures

The rules also require we consider the extent to which the distributor is able to offer efficient pricing structures in our design and implementation of a DMIS.¹⁶¹ Efficient pricing structures reflect the true costs of supplying electricity at a particular part of the network at any given time. These tariff structures would price electricity highest during peak demand periods, reflecting the high costs of transporting energy when a network utilisation is at its highest. This price signal would discourage grid electricity usage at these times, lowering peak demand and adjusting network utilisation downwards.

At present, SA Power Networks' ability to use efficient price signals is constrained by the low penetration of the required metering and other enabling technologies. We consider that efficient pricing, enabled by 'smarter' grid technologies will have a significant impact on distribution network utilisation in the future. We consider the DMIA incentivises distributors to trial measures that will assist the transition of networks to more efficient pricing.

Interaction with our other incentive schemes

The DMIA intends to encourage businesses to investigate and implement innovative demand management strategies, regardless of their potential efficiency. In developing and implementing the DMIS in SA, we must consider how it could potentially interact with our other incentive schemes.¹⁶² Neither our expenditure incentive schemes (EBSS and CESS) nor STPIS intend to discourage a distributor from using its DMIA allowance.

The DMIA allowance is independent of the revenue adjustments that will take place under our other incentive schemes. Any potential substitution between opex and capex resulting from projects approved under the DMIA will be incentive-neutral as our proposed EBSS and CESS provide balanced incentives for opex and capex savings.

¹⁵⁹ NER, clause 6.6.3(b)(2).

¹⁶⁰ NER, clause 6.6.3(b)(6).

¹⁶¹ NER, clause 6.6.3(b)(3).

¹⁶² NER, clause 6.6.3(b)(4).

4 Expenditure forecasting methodology

This section sets out our intention to apply our expenditure forecast assessment guideline (guideline)¹⁶³ including the information requirements to SA Power Networks for the 2015–2020 regulatory control period. We propose applying the guideline as it sets out our enhanced expenditure assessment approach. It outlines to the distributors and interested stakeholders the types of assessments we will do to determine efficient expenditure allowances, and the information we require from the businesses to do so.

We were required to develop the guideline under the rules.¹⁶⁴ The guideline is based on a nationally consistent reporting framework allowing us to compare the relative efficiencies of distributors and decide on efficient expenditure allowances. The rules required SA Power Networks to advise us by 30 November 2013 of the methodology they propose to use to prepare forecasts.¹⁶⁵ In the F&A we must advise whether we will deviate from the guideline.¹⁶⁶ This will provide clarity to the distributors on how we will apply the guideline and the information they should include in their regulatory proposals.

The guideline contains a suite of assessment/analytical tools and techniques to assist our review of regulatory proposals by network service providers. We intend to apply all the assessment tools set out in the guideline. The tool kit consists of:

- models for assessing proposed replacement and augmentation capex
- benchmarking (including broad economic techniques and more specific analysis of expenditure categories)
- methodology, governance and policy reviews
- predictive modelling and trend analysis
- cost benefit analysis and detailed project reviews.¹⁶⁷

We developed the guideline to apply broadly to all electricity transmission and distribution businesses. However, some customisation of the data requirements contained in the guideline might be required. This is particularly in regard to services that we classify in different ways and are subject to different forms of control. For example, nationally consistent data for benchmarking and trend assessment of public lighting costs may not be sufficient to scrutinise the particular pricing models employed by particular distributors, or indeed the guideline itself does not explicitly require these distributors to submit or justify inputs to such models. We expect that these data customisation issues would be addressed through the Regulatory Information Notice that we will issue to SA Power Networks for the next regulatory control period. This should occur after we have finalised our decisions on classification and form of control.

¹⁶³ We published this guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864

¹⁶⁴ NER, clauses 6.4.5, 6A.5.6, 11.53.4 and 11.54.4.

¹⁶⁵ NER, clauses 6.8.1A(b)(1) and 11.60.3(c).

¹⁶⁶ NER, clause 6.8.1(b)(2)(viii).

¹⁶⁷ AER, *Explanatory statement: Expenditure assessment guideline for electricity transmission and distribution*, 29 November 2013, pp. 44-46.

5 Depreciation

As part of the roll forward methodology, when the RAB is updated from forecast capex to actual capex at the end of a regulatory control period, it is also adjusted for depreciation. This attachment sets out our preliminary approach to calculating depreciation when the RAB is rolled forward to the commencement of the 2020–2025 regulatory control period.

The depreciation we use to roll forward the RAB can be based on either:

- actual capex incurred during the regulatory control period (actual depreciation). We roll forward the RAB based on actual capex less the depreciation on the actual capex incurred by the distributor; or
- the capex allowance forecast at the start of the regulatory control period (forecast depreciation). We roll forward the RAB based on actual capex less the depreciation on the forecast capex approved for the regulatory control period.

The choice of depreciation approach is one part of the overall capex incentive framework.

Consumers benefit from improved efficiencies through lower regulated prices. Where a CESS is applied, using forecast depreciation maintains the incentives for distributors to pursue capex efficiencies, whereas using actual depreciation would increase these incentives. There is more information on depreciation as part of the overall capex incentive framework in our capex incentives guideline. In summary:

- If there is a capex overspend, actual depreciation will be higher than forecast depreciation. This means that the RAB will increase by a lesser amount than if forecast depreciation were used. So, the distributor will earn less revenue into the future (i.e. it will bear more of the cost of the overspend into the future) than if forecast depreciation had been used to roll forward the RAB.
- If there is a capex underspend, actual depreciation will be lower than forecast depreciation. This means that the RAB will increase by a greater amount than if forecast depreciation were used. Hence, the distributor will earn greater revenue into the future (i.e. it will retain more of the benefit of an underspend into the future) than if forecast depreciation had been used to roll forward the RAB.

The incentive from using actual depreciation to roll forward the RAB also varies with the life of the asset. Using actual depreciation will provide a stronger incentive for shorter lived assets compared to longer lived assets. Forecast depreciation, on the other hand, leads to the same incentive for all assets.

5.1 AER's preliminary position

Our preliminary approach is to use the forecast depreciation approach to establish the RAB at the commencement of the 2020–2025 regulatory control period for SA Power Networks. We consider this approach will provide sufficient incentives for the distributors to achieve capex efficiency gains over the 2015–2020 regulatory control period.

5.2 AER's assessment approach

We must decide at our determination whether we will use actual or forecast depreciation to establish a distributor's RAB at the commencement of the following regulatory control period.

We are required to set out in our capex incentives guideline our process for determining which form of depreciation we propose to use in the RAB roll forward process. Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:

- any other incentives the service provider has to undertake efficient capex
- substitution possibilities between assets with different lives
- the extent of overspending and inefficient overspending relative to the allowed forecast
- the capex incentive guidelines
- the capital expenditure factors.

5.3 Reasons for AER's preliminary position

Consistent with our capex incentives guideline, we propose to use the forecast depreciation approach to establish the RAB at the commencement of the 2020–25 regulatory control period.

We had regard to the relevant factors in the rules in developing the approach to choosing depreciation set out in our capex incentives guideline.

Our approach is to apply forecast depreciation except where:

- there is no CESS in place and therefore the power of the capex incentive may need to be strengthened, or
- a distributor's past capex performance demonstrates evidence of persistent overspending or inefficiency, thus requiring a higher powered incentive.

In making our decision on whether to use actual depreciation in either of these circumstances we will consider:

- the substitutability between capex and opex and the balance of incentives between these
- the balance of incentives with service
- the substitutability of assets of different asset lives.

We have chosen forecast depreciation as our default approach because, in combination with the CESS, it will provide a 30 per cent reward for capex underspends and 30 per cent penalty for capex overspends, which is consistent for all asset classes. In developing our capex incentives guideline, we considered this to be a sufficient incentive for a distributor to achieve efficiency gains over the regulatory control period in most circumstances.

SA Power Networks is not currently subject to a CESS but we propose to apply the CESS in the next regulatory control period. We discuss this further in section 3.3.

For SA Power Networks, at this stage, we consider the incentive provided by the application of the CESS in combination with the use of forecast depreciation and our other ex post capex measures should be sufficient to achieve the capex incentive objective. Therefore, we do not see the need to apply actual depreciation at this time.

6 Other matters

6.1 Jurisdictional derogations – side constraint to fixed supply charge for small customers

Under the provision of clause 9.29.5 (d) of the rules, we applied the following side constraint to distribution tariffs for small customers for the 2010–2015 regulatory control period:

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

However, clause 9.29.5 (e) allows us to reconsider whether the above side constraint should continue with or without modification in preparing the framework and approach paper for the 2015–2020 distribution determination.

The side constraint to the fixed supply charge for small customers under the jurisdictional derogation is in addition to the 2% tariff basket side constraints under clause 6.18.6 of the rules.¹⁶⁸

6.1.1 AER's preliminary position

We consider that a national approach to pricing structures should be adopted rather than a jurisdictional specific requirement that may inhibit adjustment towards more efficient pricing. Pricing is being considered more broadly by the AEMC through changes to the network pricing arrangements arising from the Power of Choice Review.

6.1.2 Reasons for AER's preliminary position

The likely purpose of the restriction on increases to the small customer fixed supply charge component is to offer more protection to low energy consumption customers. However, constraints such as this could potentially hinder the flexibility of network businesses in responding to new requirements to price efficiently and also conceivably recovering their required revenue. There is no clear indication that this is likely to be the case for SA Power Networks as no issues have arisen in relation to this constraint in pricing proposals to date. In the current regulatory control period increases to the fixed supply charge component for small customers have risen but remain below the side constraint, starting from approximately \$5 in 2010–11 to \$9 in 2013–14.

The composition of the network and its use is changing and is likely to undergo further changes over the next regulatory period. Customers are seeking ways to reduce their exposure to energy costs and this is evident in recent years with the significant uptake of solar photovoltaic generation in South Australia. The pricing of energy delivery also needs to adapt as the distribution network is still required to deliver energy to customers at peak periods that occur on infrequent occasions during the year.

Cost reflective pricing is not a new concept but in considering appropriate structures for cost recovery, governments have expressed concerns with pricing impacts on disadvantaged customers. This has

¹⁶⁸ A tariff class is a group of customers with similar load and connection profile. For example, in South Australia all residential customers are grouped together as a tariff class. The (CPI-X) constraint for 2013–14 as set out in 2010–15 price determination is 9.7 per cent. The side constraint for this tariff class requires that the weighted average distribution tariff for SAPN should not increase more than 2 per cent above the (CPI-X) constraint. Therefore the weighted average distribution tariff increase for this tariff class should not exceed 11.9 per cent.

led to restrictions on pricing for equity reasons. The Productivity Commission recently highlighted this intervention:¹⁶⁹

And of direct relevance to time-based pricing are instances of jurisdictional governments intervening implicitly or explicitly to modify charging regimes for equity reasons, such as:

South Australian legislation setting out derogations from the Rules for the 2010 distribution determination, and requiring that fixed supply charges not increase by more than \$10 per year

Such instances are in conflict with the principle endorsed by all Australian governments that support for low-income or disadvantaged consumers should be provided through targeted and transparent instruments.

Distribution pricing is currently being considered by the AEMC. On 14 November 2013, the AEMC released for consultation a SCER rule change proposal seeking amendments to the distribution pricing principles.¹⁷⁰ This rule change is the outcome of the AEMC's Power of Choice Review.¹⁷¹ The AEMC concluded that efficient and flexible pricing options are important tools to help consumers to adapt their consumption patterns and hence manage expenditure. The AEMC recommended to SCER a package of rule changes to address identified deficiencies in the current distribution network pricing arrangements, these included amongst other things:

- changes to the distribution pricing principles to facilitate distributors to set efficient and flexible network tariffs
- possible changes to the network pricing side constraints that prohibit price changes from one year to the next.¹⁷²

The proposed rules would require distributors to have a more efficient pricing structure, for example, to better align their price structure with costs. This may mean that the fixed charge component of distribution tariffs may increase more than in the past to reflect the fact that network costs are largely fixed. This means the constraint on the fixed supply charge for small customers may hinder SA Power Networks' ability to rebalance its tariff structures to achieve a more efficient pricing outcome.

Further and more broadly, some elements of the SCER rule change may negate the need for quantitative constraints as a means of providing stability and certainty in network tariffs. This includes such things as:

- requiring distributors to prepare a tariff structures statement in consultation with consumers and to which they will be bound on an annual basis – therefore they will not be able to change tariff structures year on year, without consultation and justifying the greater efficiency of the modifications
- in preparing their tariff structures statement, distributors would also need to comply with a new pricing principle that requires them to consider consumer impacts of tariffs.

Restrictions may also inhibit innovative tariff design that charges higher prices for customers who consume more energy at peak times through, for example, greater air-conditioner use. Such

¹⁶⁹ Productivity Commission Inquiry Report, *Electricity Network Regulatory Frameworks No. 62*, 9 April 2013 (Chapter 11 – moving to time-based pricing for the distribution network), p.444.

¹⁷⁰ AEMC, *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, Consultation Paper*, 14 November 2013.

¹⁷¹ AEMC, *Power of choice review - giving consumers options in the way they use electricity, Final Report*, 30 November 2012.

¹⁷² AEMC, *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, Consultation Paper*, 14 November 2013, p. 9.

innovative tariff structures would require such customers to pay their fair share of the costs. SA Power Networks has commenced a small scale pilot of capacity pricing, for small customers equipped with interval meters.¹⁷³ Capacity pricing uses a pre-determined capacity price component based on the customers' maximum demand for electricity rather than relying principally on total energy consumed. This ongoing trial includes incentives for the trial participants to manage their demand during summer, particularly in the afternoon and early evening when residential demands are at their highest. If the trial demonstrates the tariff options to be effective in reducing peak network demand levels or growth, SA Power Networks may propose to introduce some form of capacity based tariff as an option for small customers in the immediate future.

6.1.3 Conclusion

We consider that a national approach to pricing structures should be adopted. This does not mean that price stability through constraints on tariff movements or other consumer protection measures should not be adopted. Rather, they should be considered and applied consistently. On this basis we seek stakeholder comments on whether the \$10 cap on fixed supply charge price increases should continue, with or without modification.

6.2 Dual function assets

The rules state that the F&A must include our determination under clause 6.25(b) as to whether or not Part J of chapter 6A is to be applied to determine the pricing of any transmission standard control services provided by any dual function assets owned, controlled or operated by a distributor.¹⁷⁴

Under clause 6.25(a) of the rules, if SA Power Networks owns, operates or controls dual function assets it must inform us by 30 June 2013. After reviewing the information provided, we must make a determination as to whether Part J of chapter 6A of the rules should apply to transmission standard control services provided by these dual function assets.

A dual function asset is:

any part of a network owned, operated or controlled by a DNSP 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).

SA Power Networks has advised us that it does not have any dual function assets.¹⁷⁵ We will therefore not make any determination under clause 6.25(b) of the rules for the purposes of this F&A.

¹⁷³ SA Power Networks, *Annual Pricing Proposal 2013-2014*, p. 31.

¹⁷⁴ NER, clause 6.8.1(b)(1)(ii).

¹⁷⁵ SA Power Networks, Email dated 2 September 2013.

Appendix A: Rule requirements for classification

Distribution service or unregulated service

We must consider whether the service meets the rules definition of a distribution service, which is 'a service provided by means of, or in connection with, a distribution system'.¹⁷⁶

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

Chapter 10 of the rules further expands distribution services to 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 distributor, but excluding services provided over a transmission network.

Direct control or negotiated service

We must have regard to four factors when classifying distribution services as either direct control services or negotiated distribution services.¹⁷⁷

1. the form of regulation factors in section 2F of the NEL:

- the presence and extent of any barriers to entry in a market for electricity network services
- the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other electricity network service provided by the network service provider
- the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other service provided by the network service provider in any other market
- the extent to which any market power possessed by a network service provider is, or is likely to be, mitigated by any countervailing market power possessed by a network service user or prospective network service user
- the presence and extent of any substitute, and the elasticity of demand, in a market for an electricity network service in which a network service provider provides that service
- the presence and extent of any substitute for, and the elasticity of demand in a market for, elasticity or gas (as the case may be)
- 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.¹⁷⁸

¹⁷⁶ NER, Chapter 10, definition of a 'distribution service'.

¹⁷⁷ NER, clause 6.2.1(c).

¹⁷⁸ NEL, s. 2F.

2. the form of regulation (if any) previously applicable to the relevant service or services, and, in particular, any previous classification under the present system of classification or under the present regulatory system (as the case requires)¹⁷⁹
3. the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)¹⁸⁰
4. any other relevant factor.¹⁸¹

The rules specify additional requirements for services we have regulated before.¹⁸² We must act on the basis that, unless a different classification is clearly more appropriate:

1. There should be no departure from a previous classification (if the services have been previously classified); and
2. If there has been no previous classification - the classification should be consistent with the previously applicable regulatory approach.

Standard control or alternative control

We must have regard to six factors when classifying direct control services as either standard control or alternative control services:¹⁸³

1. the potential for development of competition in the relevant market and how the classification might influence that potential
2. the possible effects of the classification on administrative costs of us, the distributor and users or potential users
3. the regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made
4. the desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction)
5. the extent that costs of providing the relevant service are directly attributable to the customer to whom the service is provided, and
6. any other relevant factor.¹⁸⁴

In classifying direct control services that have previously been subject to regulation under the present or earlier legislation, we must also follow the requirements of clause 6.2.2(d) of the rules.

¹⁷⁹ NER, clause 6.2.1(c)(2).

¹⁸⁰ NER, clause 6.2.1(c)(3).

¹⁸¹ NER, clause 6.2.1(c).

¹⁸² NER, clause 6.2.1(d).

¹⁸³ NER, clause 6.2.2(c).

¹⁸⁴ NER, clause 6.2.2(c).

Appendix B: Classification of distribution services in 2015–20 regulatory control period

This appendix sets out our classification of SA Power Networks' (formerly ETSA Utilities') distribution services for the 2015–2020 regulatory control period. Italicised terms are defined in the rules.

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*.
 - (i) with higher quality or reliability standards, or lower quality or reliability standards (where permissible), than are required by the rules or any other applicable regulatory instruments, or
 - (ii) in excess of levels of service or plant ratings required to be provided by SA Power Networks' 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 rules, or
 - iii. other *network services* that are classified as *negotiated distribution services* in sections B.6 to B.15 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*.
 - (i) with higher quality or reliability standards, or lower quality or reliability standards (where permissible), than are required by the rules or any other applicable regulatory instruments, or
 - (ii) in excess of levels of service or plant ratings required to be provided by SA Power Networks assets, or
 - ii. 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 rules, or
 - iii. other *connection services* that are classified as *negotiated distribution services* in sections B.6 to B.15 of this appendix B.

B.3 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.4 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
 - ii. meter installation services in respect of meters meeting the requirements of a *metering installation* type 6
 - iii. quarterly meter read services in respect of meters meeting the requirements of a *metering installation* type 6, and
 - iv. energy data and storage services, unscheduled meter reading and metering investigation.
- b. For the purposes of this clause, meter provision services include, but are not necessarily limited to, any asset related and administrative costs associated with the provision, maintenance, and replacement of the meter (including circumstances in which SA Power Networks' meter is replaced by that of another meter provider).

B.5 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 SA Power Networks distribution licence as in force at 30 June 2005.
- c. For the purposes of this clause, meter provision services include, but are not necessarily limited to, any asset related and administrative costs associated with the provision, installation, maintenance, and replacement of the meter (including circumstances in which SA Power Networks' meter is replaced by that of another meter provider).

Negotiated distribution services

B.6 Non-standard network services

- a. 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 rules or any other applicable regulatory instruments, or
 - ii. in excess of levels of service or plant ratings required to be provided by SA Power Networks' assets.

B.7 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 rules or any other applicable regulatory instruments, or
 - ii. in excess of levels of service or plant ratings required to be provided by SA Power Networks' assets.

B.8 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 rules.
- b. 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 rules.
- c. Responding to an enquiry in relation to the provision of a new *connection point* referred to in paragraph B.8(a) or (b).
- d. The provision of technical specifications in relation to the upgrading of the capability of a *connection point* referred to in paragraph B.8(a) or (b).
- e. Preliminary communications with a customer, being an existing or potential *distribution network user* where more than 6 hours work is required.

B.9 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, or
 - 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 SA Power Networks would ordinarily install (including prepayment meter systems), which is installed at the request of a retailer or a *distribution network user*.
- b. In relation to energy data services, the provision of special meter readings and associated services.

B.10 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 SA Power Networks' distribution licence as in force at 30 June 2005.

B.11 Public lighting services

- a. Street lighting use of system services
 - i. The provision of public lighting assets, and the operation and maintenance of those assets where SA Power Networks retains ownership of the assets.
- b. Customer lighting equipment rate 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 SA Power Networks where customers retain ownership of the assets and are responsible for all maintenance (including replacement of failed lamps).

B.12 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.13 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. Provision of network access management services for a distribution network user or external party.

B.14 Embedded generation services

- a. Services and system augmentation or extension required to receive energy from an embedded generator and meet the requirements of the rules.

- b. Services associated with non-compliance of the embedded generator with the *connection agreement*, including but not limited to reactive power, power factor, harmonics, voltage dips and test supply arrangements.

B.15 Other Services

- a. The following services provided in connection with the *Electricity Metering Code* or the rules:
 - i. application for an account or new supply
 - ii. provision of a copy of various codes
 - 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).
- i. Costs incurred by SA Power Networks as a result of a customer not complying with SA Power Networks' standard connection and supply contract or other obligation.
- j. Additional costs incurred by SA Power Networks where service provision could not be undertaken and/or completed as planned due to the actions, or inaction, of a customer or their agent.
- k. Provision of a television or radio interference investigation where it is determined that the distribution system is not the cause of the interference.

- l. Provision of a supply interruption investigation where it is determined that the distribution system was not the cause of the interruption.
- m. Provision of information to *distribution network users* or third parties not related to connection enquiries.
- n. Recovery of costs associated with the larceny of supply, including the costs associated with repairing or replacing damaged equipment and investigation costs where SA Power Networks determines that larceny of supply has occurred.
- o. Emergency recoverable works, including the repair of damage caused to the distribution network by a third party, where costs are recovered.
- p. Third party connection works charges, for work not undertaken by SA Power Networks, this includes, but is not limited to:
 - i. Specification services
 - ii. Works design compliance
 - iii. Works reinspection.
- q. Provision of access permits or clearance to work on or near the distribution system.
- r. Off-peak conversion services.
- s. Carrying out planning studies and analysis relating to distribution, including sub-transmission and dual function asset connection applications.
- t. Work required for network tariff change requests.
- u. Recovery of debt collection costs.
- v. Negotiation for the provision of services.
- w. Attendance at the customer's premises to perform a statutory right where access is prevented.

Appendix C: Efficient pricing

This appendix provides high level considerations about efficient pricing structures and analyses pricing efficiency under the WAPC in the current and previous regulatory period.

Broadly, we consider that efficient prices will incorporate two key characteristics:

- the underlying cost of supply
- customers willingness to pay.

While there are a variety of methods of incorporating these characteristics, we consider that the resulting prices from each will include many of the same features. Firstly, because the majority of distributors cost of supply are fixed or related to peak demand, efficient prices will be structured around fixed or peak prices.¹⁸⁵ Secondly, as customers' willingness to pay for connection to the network is generally higher than for electricity consumption, where the price must be set above the cost of supply, the largest margin is likely to be applied to fixed (connection) prices.

Our analysis of pricing efficiency¹⁸⁶ under the WAPC in the current and previous regulatory period demonstrates:

- insufficient evidence indicating SA Power Networks' revenue recovered under efficient charging parameters relative to inefficient charging parameters has increased over the current regulatory control period
- revenue recovered by the NSW and Victorian distributors' under efficient charging parameters relative to inefficient charging parameters did not increase over the period
- the NSW distributors' joint submission to the NSW Stage 1 F&A paper does not demonstrate that the WAPC has resulted in an overall increase in pricing efficiency¹⁸⁷
- the tariffs the NSW distributors' utilise most have not increased in efficiency over the period.

On this basis, we consider there has not been an increase in pricing efficiency across the distributors subject to the WAPC.

Charging parameter revenue recovery

Broadly, we consider that efficient pricing would match prices to cost drivers. The distributors' costs are primarily fixed or linked to peak demand and therefore, charges for peak usage, peak demand/capacity and fixed charges are generally efficient. While energy based charges that are unrelated to the networks peak periods and capacity are generally not efficient.

On this basis, we consider that high proportions of revenue recovered from peak usage, peak demand/capacity and fixed charges are likely to represent efficient pricing. While high proportions of

¹⁸⁵ Peak prices include peak energy, demand and capacity prices.

¹⁸⁶ Broadly, we consider that efficient pricing would match prices to cost drivers. The distributors' costs are primarily fixed or linked to peak demand and therefore charges for peak usage, peak demand/capacity and fixed charges are generally efficient (efficient charging parameters). While energy based charges that are unrelated to the network's peak period and capacity are generally not efficient (inefficient charging parameters).

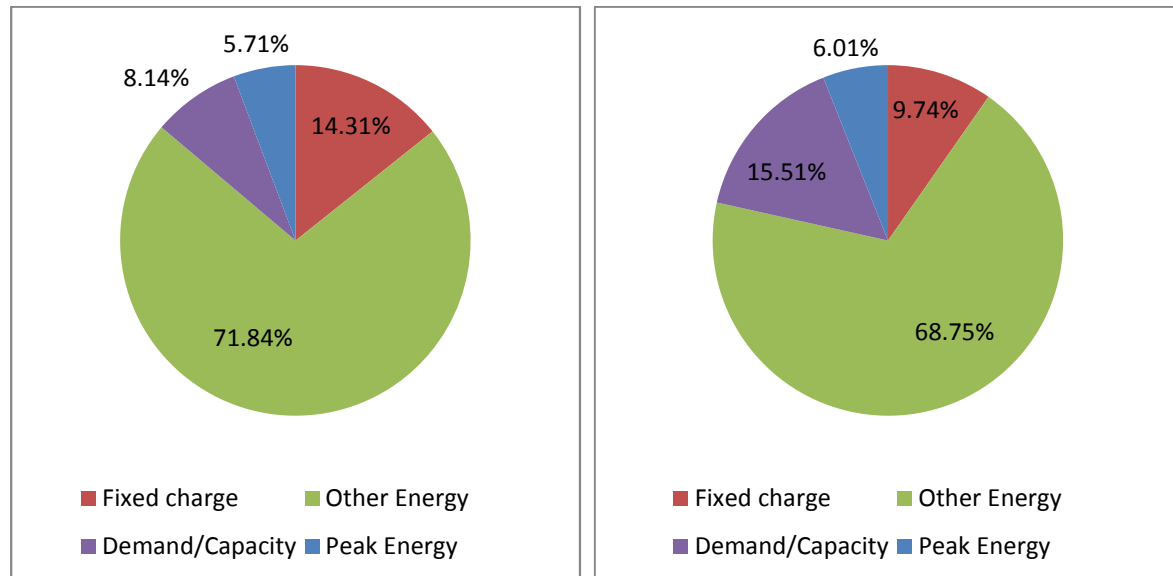
¹⁸⁷ AER, *Stage 1 Framework and approach paper for NSW DNSPs Transitional regulatory control period 1 July 2014 to 30 June 2015, Subsequent regulatory control period 1 July 2015 to 30 June 2019*, Appendix E, March 2013.

revenue recovered from flat, inclining block and off peak charges are likely to represent inefficient pricing.

Given the recent introduction of the WAPC form of control for SA Power Networks, only three years of data is available for the analysis (from 2009–10 to 2011–12).

Charts C.1 and C.2 compares the revenue recovery by tariff type for SA Power Networks at the beginning of the regulatory control period to the most recent year where audited data is available under the WAPC.

Chart C.1: SAPN revenue by tariff type 2009-10 **Chart C.2: SAPN revenue by tariff type 2011-12**

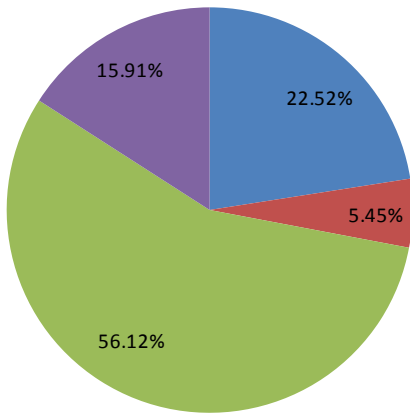


We found that there appears to be some moderate improvement in efficient pricing as the revenue recovered from the fixed charge, peak energy and demand/capacity increased by approximately 3% over the three year period. However, revenues collected from energy based tariffs still form a vast majority of SA Power Networks' revenue.

This comparative analysis should be treated with caution as it is based on data over a short timeframe. Given this limitation, we consider it is appropriate to broaden the analysis to include other jurisdictions where longer term data is available.

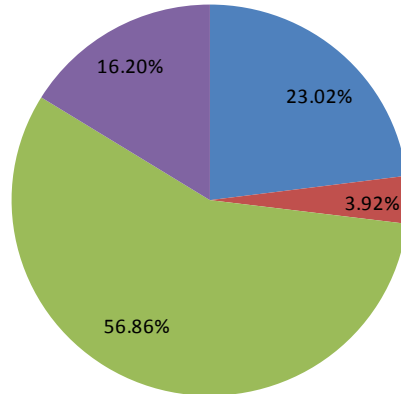
Charts C.3 to C.10 presents revenue recovery by tariff type for the NSW and Victorian distributors over the period where reliable data is available under the WAPC.

Chart C.3: Victorian DNSPs revenue by tariff type 2006



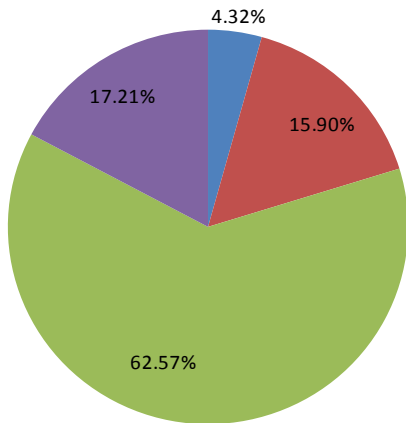
■ Peak Energy ■ Fixed Charge
■ Other Energy ■ Capacity

Chart C.4: Victorian DNSPs revenue by tariff type 2010



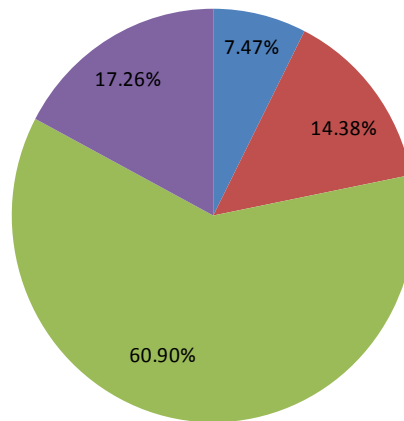
■ Peak Energy ■ Fixed Charge
■ Other Energy ■ Capacity

Chart C.5: NSW DNSPs revenue by tariff type 2004-05



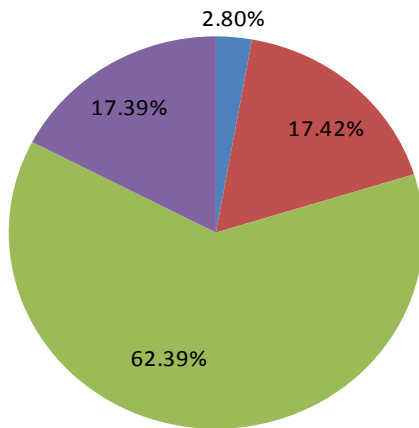
■ Peak Energy ■ Fixed Charge
■ Other Energy ■ Capacity

Chart C.6: NSW DNSPs revenue by tariff type 2008-09



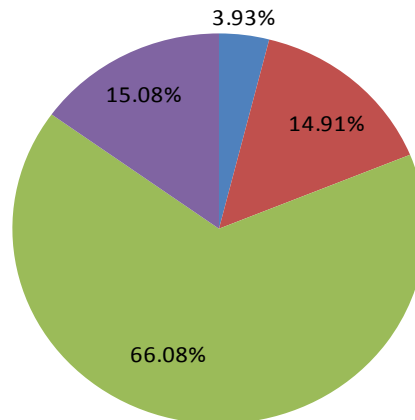
■ Peak Energy ■ Fixed Charge
■ Other Energy ■ Capacity

**Chart C.7: Essential and Endeavour Energy
Energy revenue by tariff type 2004-05**



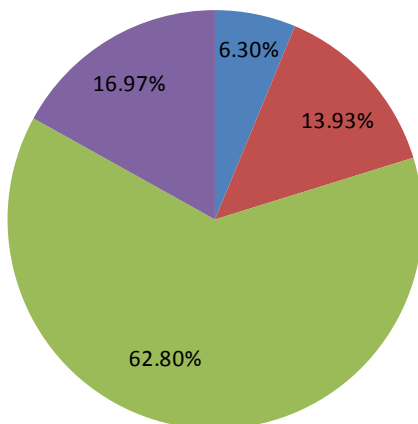
■ Peak Energy ■ Fixed Charge
■ Other Energy ■ Capacity

**Chart C.8: Essential and Endeavour
revenue by tariff type 2008-09**



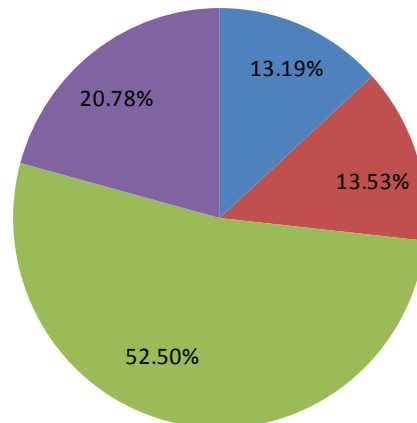
■ Peak Energy ■ Fixed Charge
■ Other Energy ■ Capacity

Chart C.9: Ausgrid revenue by tariff type 2004-05



■ Peak Energy ■ Fixed Charge
■ Other Energy ■ Capacity

**Chart C.10: Ausgrid revenue by tariff type
2008-09**



■ Peak Energy ■ Fixed Charge
■ Other Energy ■ Capacity

Charts C.3 to C.10 demonstrate that, with the exception of Ausgrid, NSW and Victorian distributors did not increase the proportion of revenue derived from efficient tariff types over the period. For the Victorian distributors very little changed over the period. Slight increases in other energy, peak energy and capacity were offset by a drop in fixed charges. For Essential and Endeavour Energy the

proportion of revenue from other energy tariffs increased over the period. Simultaneously, the proportion of revenue from fixed and demand/capacity charges decreased.

One observation we draw from the analysis is that distributors, including SA Power Networks, under WAPCs have generally utilised inclining block tariffs while distributors under other control mechanisms have utilised two-part tariffs. Table C.1 provides the DUOS tariff structure for each distributor within the NEM.¹⁸⁸

Table C.1 Most utilised residential customer tariff type by control mechanism

Control mechanism	Distributor	Two-part tariff	Inclining block tariff	Declining block tariff
Weighted Average Price Cap	Ausgrid			X
	Endeavour Energy		X	
	Essential Energy	X		
	CitiPower		X	
	Powercor		X	
	SP Ausnet		X	
	Jemena		X	
	UED		X	
	SA Power Networks		X	
Revenue Cap	Aurora	X		
	Energex	X		
	Ergon Energy	X		
Average Revenue Cap	ActewAGL	X		

Source: AER analysis

We consider this is evidence of less efficient pricing under the WAPC. We consider that block tariffs are less efficient pricing structures than two-part tariffs.

¹⁸⁸ We consider the relevant tariffs for this analysis are the DUOS tariffs. While the overall network tariffs are set by the distributors, only DUOS tariffs are subject to the WAPC.

Under block tariff structures, distributors charge consumers different prices for different levels of consumption at a given point in time. The marginal cost of a consumers' consumption is constant at a given point in time. Therefore, prices under inclining block tariffs cannot be set at marginal cost because there is one marginal cost while distributors charge multiple prices. This reduces allocative efficiency because consumers face prices that do not reflect the cost of providing the service. Alternatively, prices can be set efficiently under two-part tariffs because distributors can set the consumption charge at the marginal cost of consumption. Recent economic literature has measured losses in allocative efficiency from block tariff structures, finding that losses are often significant.¹⁸⁹ We therefore consider the predominant use of block tariff structures under the WAPC is evidence of less efficient pricing under the WAPC.

In addition to inefficiencies caused by a lack of cost reflectivity, block structure tariffs create substantial information asymmetries due to their complexity. That is, because the price varies as consumption increases, it is difficult for customers to determine the price they are being charged for electricity usage. A customer on a block tariff needs to know their households quarterly consumption at every point in time to be able to determine the price. In practice, this requires customers to have detailed information regarding their household consumption profile. Given the lack of customer awareness in this area, we consider it is more likely that block tariff structures will send a blunt signal of higher use costing more (inclining block tariff) or less (declining block tariff). We consider these signals are not efficient, as they do not reflect the cost of providing the service.

We understand that block structure tariffs may provide equity benefits. That is, lower bills for low income customers. In jurisdictions outside of Australia that have introduced inclining block tariffs, equity has often been a primary consideration. We do not consider this is a benefit of block structure tariffs in the NEM. Firstly, equity is not one of the rules criteria for determining the form of control mechanism. Secondly, the economic literature provides that the equity benefits from block structure tariffs are often minor relative to efficiency detriments and other (non-price based) equity schemes.¹⁹⁰

Specific tariff analysis

The following section analyses SA Power Networks' most common tariffs. It looks at the structure, relative size of prices, and changes made by the SA Power Networks throughout the period.

The inclining tariff block based on usage is SA Power Networks' most used residential customer tariff. It consists of one fixed charge component and 4 variable charge components based on usage level. The movements for each component of the tariff over the current control regulatory period is set out in Table C.2 below.

¹⁸⁹ Severin Borenstein, *The Redistributive Impact of Nonlinear Electricity Pricing*, *American Economic Journal: Economic Policy* 2012, 4(3): 56–90. p. 56.

¹⁹⁰ Severin Borenstein, *The Redistributive Impact of Nonlinear Electricity Pricing*, *American Economic Journal: Economic Policy* 2012, 4(3): 56–90. p. 57.

Table C.2 SAPN standard residential customer tariff

	Fixed charges (\$ per year)	Changes in fixed charge from previous year (%)	Block 1 usage rate c/kWh	Changes in block 1 usage rate from previous year (%)	Block 2 usage rate c/kWh	Changes in block 2 usage rate from previous year (%)	Block 3 usage rate c/kWh	Changes in block 3 usage rate from previous year (%)	Block 4 usage rate c/kWh	Changes in block 4 usage rate from previous year (%)
2010-11	81.37		5.42		7.62		9.07		9.07	
2011-12	88.91	9.26	6.58	21.38	9.25	21.37	11.01	21.39	11.01	21.39
2012-13	94.76	6.57	8.14	23.73	10.73	15.94	12.76	15.94	12.76	15.94
2013-14	102.09	7.74	9.25	13.66	12.05	12.33	14.33	12.33	14.33	12.33

Note: All tariffs excludes metering and solar PV pass through component.

The fixed charge component of the tariff has the lowest percentage increase over the current period, this is followed by the block 2 to 4 usage rate charges, for annual usage higher than 4000kWh, while the block 1 usage charge, for annual usage less than 4000kWh, experienced the highest percentage increase over the period.

Residential usage per customer decreased over the period from 2010–11 to 2011–12 where actual audited data is available. This created an incentive for SA Power Networks to increase the block 1 usage charge relative to the fixed charge and higher usage block charges because quantities for the higher usage blocks (usage block 2 to 4) are falling faster than quantities under the block 1 usage.

As detailed above, we consider that block tariff structures do not represent efficient pricing structures. Currently, low usage residential customers below 4000kWh face a marginal distribution price of 9.25c/kWh. All higher usage residential customers between 4000 and 10000kWh face a marginal distribution price of 12.05/kWh. We consider that these tariff charges vary substantially from marginal cost because marginal cost is relatively constant across a customers' consumption.

In general, SA Power Networks have two types of tariff structure for small and medium business customers with peak demand below 1000kVA. This customer group contributes the largest proportion of SA Power Networks' recovered revenue from business customers as a whole. The first type of tariff structure is a combination of fixed supply and usage based charges, and the second type is a combination of usage and stepped demand based charges. The former have one fixed supply charge component and five usage block charge components based on levels of peak and off-peak usage. The latter has two usage charge components for peak and off-peak time of use, and five stepped demand block components for different levels of peak demand.

One feature of the first type of tariff structure is that the charges for the 4 peak block usage are the same. The practical outcome is that this customer pays two rates for its usage depending on the time of use at peak and off-peak periods. The movements for each components of the first type of tariff structure over the current control regulatory period is set out in Table C.3 below:

Table C.3 SAPN business type 1 tariff - demand less than 1000kVA

	Fixed charges (\$ per year)	Changes in fixed charge from previous year (%)	Off-peak usage rate c/kWh	Changes in Off-peak usage rate from previous year (%)	Peak usage rate c/kWh	Changes in Peak usage rate from previous year (%)
2010-11	81.10		2.72		8.62	
2011-12	88.61	9.26	3.25	19.51	10.30	9.26
2012-13	94.43	6.57	3.83	17.80	12.14	6.57
2013-14	101.74	7.74	4.30	12.33	13.63	7.74

Note: All tariffs exclude metering and solar PV pass through components. To simplify presentation, the charges for the 4 peak block usage rates are condensed into a single rate because they are the same for all years.

The second type of tariff structure is based on an inclining tariff block for different levels of peak demand and a flat usage charge regardless of the time of use. The movements for each components of the first type of tariff structure over the current control regulatory period is set out in Table C.4 with the changes in percentage terms presented in Table C.5.

Table C.4 SAPN business type 2 tariff - demand less than 1000kVA

	Annual Block 1 demand rate \$/kVA/month	Annual Block 2 demand rate \$/kVA/month	Annual Block 3 demand rate \$/kVA/month	Annual Block 4 demand rate \$/kVA/month	Additional Demand	Peak usage rate	Off-peak usage rate
2010-11	8.2847	4.8331	3.5386	2.6749	2.6749	0.0171	0.0171
2011-12	9.8961	5.7731	4.2269	3.1952	3.1952	0.0204	0.0204
2012-13	11.6578	6.8009	4.9793	3.7640	3.7640	0.0240	0.0240
2013-14	13.0959	7.6398	5.5936	4.2283	4.2283	0.0270	0.0270

Table C.5 SAPN business type 2 tariff for demand less than 1000kVA - movement in percentage terms

	Annual Block 1 demand rate \$/kVA/month	Annual Block 2 demand rate \$/kVA/month	Annual Block 3 demand rate \$/kVA/month	Annual Block 4 demand rate \$/kVA/month	Additional Demand	Peak usage rate	Off-peak usage rate
2011-12	19.45	19.45	19.45	19.45	19.45	19.50	19.50
2012-13	17.80	17.80	17.80	17.80	17.80	17.79	17.79
2013-14	12.34	12.34	12.34	12.34	12.34	12.35	12.35

Over the current regulatory control period SA Power Networks has been allocating new customers and some existing customers to the second type of tariff as set out in tables C.4 and C.5. We consider there is a moderate increase in pricing efficiency for SA Power Networks' tariff structure for small and medium business customers through this increased use of demand based tariffs.

Efficient pricing summary

There is no material increase in pricing efficiency for SA Power Networks' tariff structure under the WAPC in the current regulatory control period. We formed this conclusion based on the following:

- Total revenue recovered from the fixed charge, peak energy and demand/capacity components increased by approximately 3 per cent over the three year period. However, revenues collected from energy based tariffs still form the vast majority of SA Power Networks' revenue
- Wide use of block tariff structures for small customers which is less efficient than a two part tariff
- There is a moderate increase in pricing efficiency for SA Power Networks' tariff structure for small and medium business customers through the increase use of demand based tariffs
- We accept that the results from the comparative analysis for SA Power Networks should be treated with caution as it is based on data over a short timeframe. However, we also factored into our consideration analysis of other distributors operating under a WAPC, which demonstrated that the distributors' most utilised tariffs have not increased in efficiency.