



**Final framework and approach for
SA Power Networks
Regulatory control period commencing 1 July
2015**

April 2014

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Inquiries about this document should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001
Tel: (03) 9290 1444
Fax: (03) 9290 1457
Email: AERInquiry@acr.gov.au

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Shortened forms

Shortened Form	Extended Form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CCP	Consumer Challenge Panel ¹
CESS	capital expenditure sharing scheme
COAG Energy Council	Council of Australian Governments Energy Council (formerly Standing Council on Energy and Resources or SCER)
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
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
RAB	regulatory asset base

¹ On 1 July 2013, we established the Consumer Challenge Panel (CCP). The CCP assists us to make better regulatory determinations by providing input on issues of importance to consumers. Regulatory determinations are technical and complex processes which can make it difficult for ordinary consumers to participate. The expert members of the CCP bring consumer perspectives to the AER to better balance the range of views considered as part of our decisions. The sub panel members for the 2015–20 SA electricity distribution price determination process includes Mr Hugh Grant, Ms Bev Hughson, Mr Bob Lim, Ms Fiona McLeod and Mr Bruce Mountain.

Shortened Form	Extended Form
SA	South Australia
SAPN	SA Power Networks
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
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).² 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 is the licensed, regulated operator of South Australia's (SA) 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 September 2013, we made a decision to review the current SA F&A for the next regulatory control period.³ This decision arose following consultation with stakeholders.⁴ Our main reason for this decision was because of significant changes to the rules, making much of the current F&A irrelevant.

The current five year SA distribution regulatory control period concludes on 30 June 2015. This paper sets out our decisions for the next regulatory control period from 1 July 2015 to 30 June 2020 on:

- control mechanisms (how we determine prices for regulated services)
- dual function assets.

It also sets out our proposed approach for the next regulatory control period on:

- distribution service classification (which services are to be regulated)
- the formulae that give effect to the control mechanisms
- service target performance incentive scheme
- efficiency benefit sharing scheme
- capital expenditure sharing scheme
- demand management incentive scheme

² In addition to regulating NEM transmission and distribution, we regulate the NEM wholesale market and administer the National Gas Rules.

³ AER, *Replacement of F&A for Queensland and South Australian electricity distribution businesses, 2015–2020*, September 2013.

⁴ NER, clauses 6.8.1(c)(1)–(3).

- small-scale incentive scheme
- application of the expenditure forecast assessment guidelines
- whether depreciation will be based on forecast or actual capital expenditure
- jurisdictional and legacy issues.

Before reaching our proposed approach, we published a preliminary positions F&A on 18 December 2013, seeking submissions from interested parties. Submissions closed on 19 February 2014, with ten responses received. We also consulted our Consumer Challenge Panel (CCP). Submissions and CCP views have been considered in reaching the decisions and proposed approaches set out in this F&A. A summary of submissions and our response is also included at appendix C.

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.⁵ We encourage SA Power Networks to also consult consumers, as part of its consumer engagement, to gain a better understanding of the type of information consumers are interested in accessing.⁶

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

Table 1 summarises the SA distribution determination process.

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
SA Power Networks 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**
SA Power Networks 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: AER

⁵ AER, *Confidentiality guideline*, 19 November 2013.

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

Part A: Overview

The F&A provides an opportunity for interested parties, including consumers, to have a say in which services we should regulate and how much control we have over determining the prices for network services. The F&A also sets out information around incentive schemes that will apply to SA Power Networks to encourage efficient investment and performance. This overview sets out our decision or proposed approach to:

- classification of distribution services (which services we will regulate)
- control mechanisms (how we will determine prices for regulated services) and the formulae that give effect to the control mechanisms
- treatment of dual function assets
- the application of a range of incentive schemes that encourage things like service quality, improvements in network reliability or efficient capital and operating expenditure
- the application of a range of expenditure forecasting expenditure tools used to test SA Power Networks' regulatory proposals
- how we will calculate depreciation of the distributors' regulatory asset base going forward.

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. When we classify distribution services we determine the nature of the economic regulation we will apply to those services.

The rules establish a limited range of service classifications, 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 SA Power Networks recover service costs by averaging them across all customers or only charging those customers 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: Classification 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.	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 ⁷ 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 Networks' services are negotiated services. This means that customers may negotiate directly with SA Power Networks for the provision of the service.⁸ 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 position is that the existing classification of these services remains appropriate.

We propose limited changes to the classification of services. This includes:

- change the classification of all type 6 metering related services, other than metering investigation requested by customers, from standard control to alternative control services.
- change the classification of all type 5 metering related services from negotiated to alternative control services.

The changes will provide customers with more transparent costing information for these services.

Direct control services

The rules set out factors we must have regard to when determining levels of economic regulation for the range of electricity distribution services. Following consideration of those factors, we may determine that a prescriptive approach is required. We will classify such services as direct control

⁷ A distribution service is a service provided by means of, or in connection with, a distribution system. NER, Chapter 10.

⁸ The rules also confer a dispute resolution role on the AER in respect of negotiated services.

services. That is, we will directly set prices distributors may charge, or set revenues distributors may recover from customers through their charges.⁹

Most distribution services fall within the network services group, which includes poles, wires, and other core infrastructure of a distribution business. These are central to a distributor's business and its broad customer base uses them. Network services are central to a distributor's monopoly power and are frequently subject to licence restrictions. Therefore, our proposed approach is to classify network services as direct control services. Other distribution services are also subject to limited, or no, supply competition. We therefore also propose to classify as direct control: some metering services and standard connection services. We must further determine whether we will classify a direct control service as a standard control or alternative control service.

Standard control services

We classify as standard control those distribution services that are central to electricity supply and therefore relied on by most (if not all) customers. Standard control services reflect the integrated nature of an electricity distribution system. The costs of providing standard control services are averaged across all customers of a distribution network and recovered through standard network charges. These standard control services form the core distribution component of an electricity bill.

We propose to classify network services, standard connection services and type 7 metering, as standard control services. These services encompass construction, maintenance and repair of the network, as well as connecting new customers.

Alternative control services

Alternative control services are customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by a single distributor. For alternative control services we set specific prices to enable the distributor to recover the full cost of each service from customers using that service. We will determine prices for individual alternative control services in a variety of ways, suitable to specific circumstances. For example, only a few customers purchase exceptional large customer metering services. It would be inefficient for all customers to fund provision of these services. Therefore our proposed approach is to classify ex services as alternative control.

Our proposed approach is to classify type 5 and most type 6 metering services as alternative control because provision of these services is likely to become open to more competition in future.

Negotiated distribution services

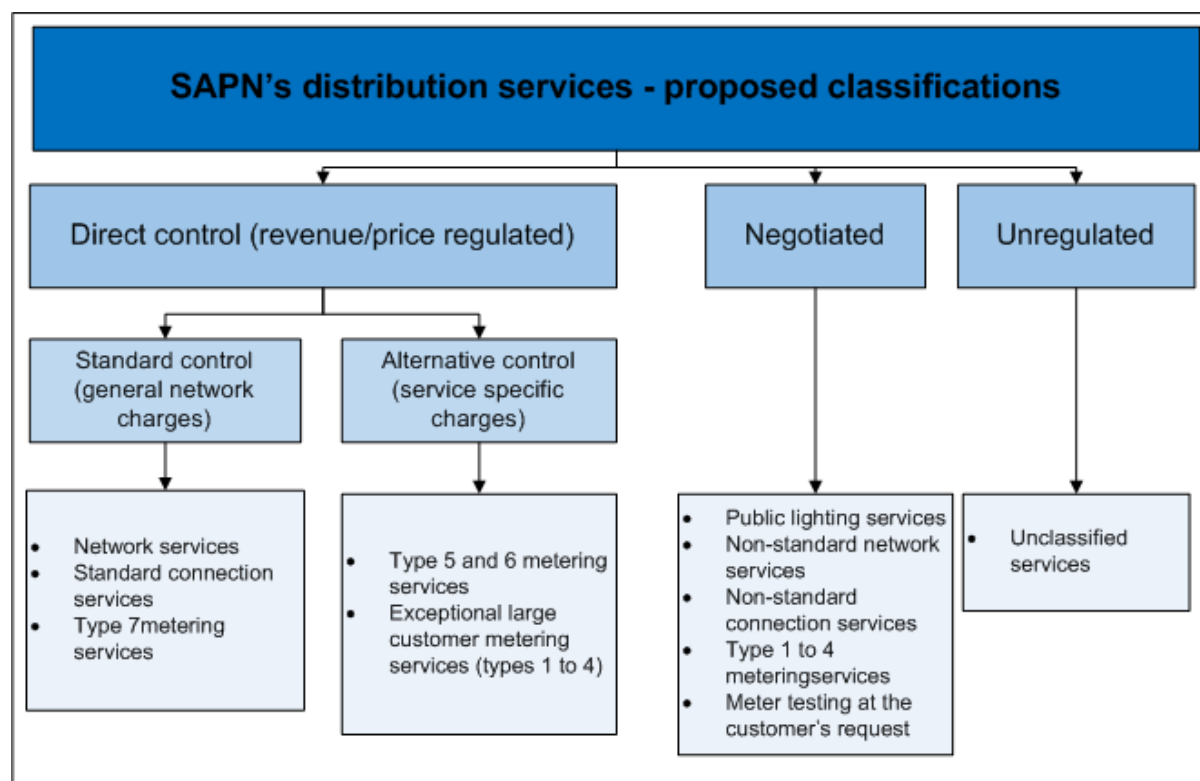
Negotiated distribution services are those we consider require a less prescriptive regulatory approach because all relevant parties have sufficient market power to negotiate provision of those services. Distributors and customers are able to negotiate services and prices according to a framework established by the rules. We are available to arbitrate if necessary.

Our proposed approach is to classify public lighting services, non-standard network services and some metering services as negotiated distribution services.

⁹ We regulate distributors by determining either the prices they may charge (price cap regulation) or by determining the revenues they may recover from customers (revenue cap regulation).

Figure 1 sets out our proposed approach on the classification of SA Power Networks' distribution services. Attachment 1 provides more information about the different types of services and the reasoning behind our position.

Figure 1: AER proposed approach for classification of SA Power Networks' distribution services



Source: AER

Control mechanisms

Following on from service classifications, our determinations must impose pricing controls on direct control service prices and/or their revenues.¹⁰ The form of control must be as set out in this F&A. The formulae that give effect to the form of control must be as set out in this F&A unless we consider unforeseen circumstances justify us departing from it.¹¹

The rules require us to decide on the form of control mechanism¹² and our proposed 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.¹³ 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.¹⁴ These include the need for efficient tariffs, administrative costs, previous regulatory

¹⁰ NER, clause 6.2.5(a).

¹¹ NER, clause 6.12.3(c).

¹² NER, clause 6.2.5(a).

¹³ NER, clause 6.2.5(b).

¹⁴ NER, clauses 6.2.5(c) and 6.2.5 (d).

arrangements and consistency. In light of the above alternatives and considerations, our decision on the form of control mechanisms for SA Power Networks are:

- standard control services— revenue cap

We consider that a revenue cap best meets the factors set out under clause 6.25(c) of the rules. We consider that a revenue cap will result in benefits to consumers through a higher likelihood of revenue recovery at efficient cost, better incentives for demand side management, less reliance on energy forecasts and better alignment with the introduction of efficient prices. Furthermore, we consider that the detriments of a revenue cap – within period pricing instability and weak pricing incentives are able to be mitigated. Therefore, our decision is to move to a revenue cap for SA Power Networks' standard control services.

- alternative control services— caps on the prices of individual services. We consider this decision will provide cost reflective price benefits.

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.¹⁵ For alternative control services, we will confirm a control mechanism basis through the distribution determination process.

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.

We outline below our 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.

¹⁵ 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.

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

Our proposed approach is 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 operating expenditure (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 proposed approach 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 capital expenditure (capex) becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices.

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. Our proposed approach is 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

Distributors have historically planned their network investment to provide sufficient capacity to provide for peak usage periods. As peak demand periods are typically brief and infrequent, network infrastructure often operates with significant redundant capacity. This underutilisation means that further investment in network capacity may not always be the most efficient means of catering for increasing peak demand. Demand management by distributors to lower or shift the demand for standard control services is incentivised through our demand management incentive scheme (DMIS).

Our proposed approach is to continue applying the DMIS to SA Power Networks in the next regulatory control period. As we intend SA Power Networks' standard control services to operate under a revenue cap, we only apply Part A of the DMIS. That is, a demand management innovation allowance (DMIA). The DMIS adds an innovation allowance to each distributor's revenue each year of the regulatory control period. In calculating the allowance, we must have regard to a range of factors around benefits to consumers and how the DMIS balances against other incentive schemes. For the next regulatory control period, we propose setting the DMIA at \$3 million in total over five years.

Small-scale incentive scheme

The rules state that we may develop a small-scale incentive scheme.¹⁸ At this stage we are not proposing to develop this scheme. Therefore, such a scheme will not apply to SA Power Networks.

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.

¹⁸ NER, clause 6.6.4.

Application of the expenditure forecast assessment guidelines

In December 2013 we published our expenditure forecast assessment guideline for electricity distribution (expenditure forecast 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 proposed approach 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.

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 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. Alternatively, we may use the capex allowance forecast as at the start of the regulatory control period.

Our proposed approach 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

We were required to apply the following side constraint to distribution tariffs for SA 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, the NER¹⁹ allow 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 and propose to remove this side constraint applying to small customers in SA. 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 and also balanced with the need for flexible pricing and tariff reform.

Dual function assets

The F&A must include our determination on whether or not the pricing of any transmission standard control services provided by any dual function assets owned, controlled or operated by a distributor applies. Dual function assets are high voltage transmission assets forming part of the distribution network. Transmission network service providers usually operate these assets. Considering

¹⁹ NER, clause 9.29.5(e).

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 own, operate or control any dual function assets. We will therefore not make any determination for the purposes of this F&A.

1 Classification of distribution services

This attachment sets out our proposed approach to the classification of SA Power Networks distribution services during the next regulatory control period. Service classification determines the nature of economic regulation, if any, applicable to specific distribution services. Classification determines whether we:

- directly control prices²⁰
- allow parties to negotiate services and prices and only arbitrate disputes if necessary, or
- do not regulate at all.

If we control prices directly, classification further determines whether a distributor recovers service costs from all of its customers or from those customers benefiting directly from specific services.²¹

Classification is important to customers as it determines which network services are included in basic electricity charges, which are sold as additional services and which we will not regulate. Our decisions reflect our assessment of a number of factors, including competition, or the potential for competition, of service supply. When necessary, we classify services with a more prescriptive form of regulation. If possible, we classify services with less prescriptive forms of regulation or do not regulate at all. If specific customers use a service we may consider classifying it to establish a user pays approach to pricing.

Service classifications must be as set out in this F&A unless we consider unforeseen circumstances justify departing from the classification as set out in this F&A.²²

The rules set out a three step classification process we must follow. We must consider a number of specified factors at each step.²³ Figure 2 outlines the classification process under the rules.

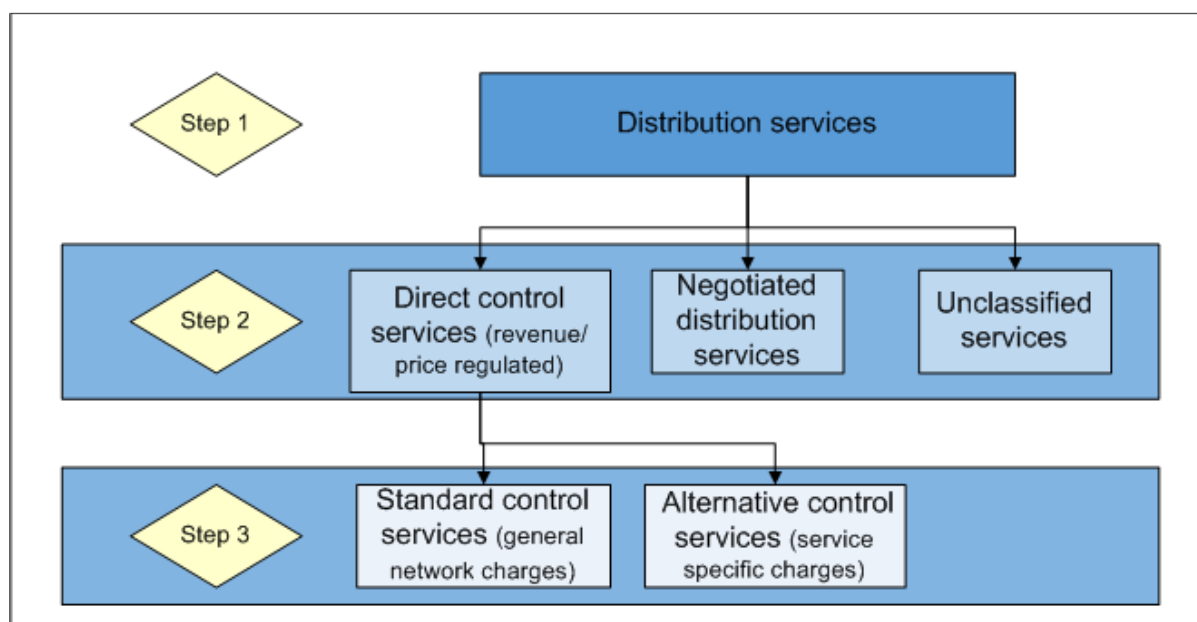
²⁰ Control mechanisms available for each service depend on their classification. Control mechanisms available for direct control services are listed by clause 6.2.5(b) of the rules. These include caps on revenue, average revenue, prices and weighted average prices. A fixed price schedule or a combination of the listed forms of control are also available. Negotiated services are regulated under part D of chapter 6 of the rules.

²¹ Standard control service costs are generally recovered through distribution use of service tariffs paid by all, or most, customers. Alternative control or negotiated service costs are generally recovered from individual customers receiving them.

²² NER, clause 6.12.3(b).

²³ NER, clauses 6.2.1 and 6.2.2.

Figure 2: Distribution service classification process



Source: AER.

As illustrated in figure 2 above:

- We must first satisfy ourselves that a service is a 'distribution service' (step 1). The rules define a distribution service, as a service provided by means of, or in connection with, a distribution system.²⁴ 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'.²⁵
- We then consider whether economic regulation of the service is necessary (step 2). If we do not consider economic regulation is warranted we will not classify the service. If economic regulation is necessary, we consider whether to classify the service as either a direct control or negotiated distribution service.
- If we consider we should classify a service as direct control, we further classify it as either a standard control or alternative control service (step 3).

Our classification decisions determine how distributors will recover the cost of providing services. Distributors recover standard control service costs by averaging them across all customers using the shared network. In contrast, distributors will charge a specific user benefiting from an alternative control service. Alternative control classification is akin to a 'user-pays' system. The whole cost of the service is paid by those customers who benefit from the service.

For services we classify as negotiated, distributors and customers will negotiate service provision and price under a framework established by the rules. Our role is to arbitrate disputes where distributors and prospective customers cannot agree. Two instruments support the negotiation process:

²⁴ NER, chapter 10, glossary.

²⁵ NER, chapter 10, glossary.

- Negotiating distribution service criteria—sets out the criteria distributors are to apply in negotiating the price, and terms and conditions, under which they supply distribution services. We will also apply the negotiating distribution service criteria in resolving disputes.
- Negotiating framework—sets out the procedures a distributor and any person wishing to use a negotiated distribution service must follow in negotiating for provision of the service.

For services we do not classify, we will have no role at all.

1.1 AER's proposed approach

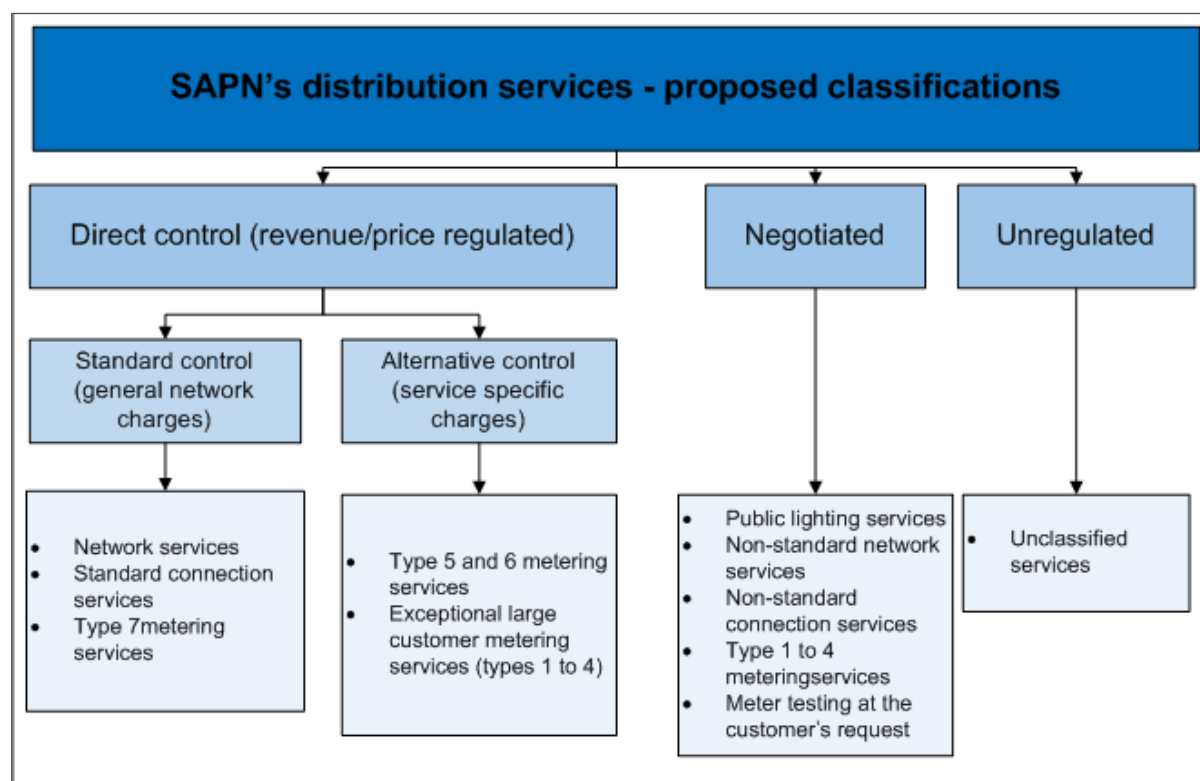
Before considering how to classify services, we consider how to group them. This allows a more straightforward approach to classification, as our classification decisions for a group of services relate to each service within the group. Our proposed approach is to group distribution services provided by SA Power Networks as:

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

We consider each service falling within the above service groups is a distribution service.²⁶ Figure 3 summarises our proposed classification of SA Power Networks' distribution services. This section summarises our proposed approach to the classification of each service group.

²⁶ See Appendix B for a list of each distribution service falling within the groups set out above.

Figure 3: Our proposed classification of SA Power Networks' distribution services



Source: AER

Network services are at the core of what an electricity distributor does, including constructing and maintaining those parts of the electricity network that everyone uses—that is, the shared distribution network. SA Power Networks provides standard network services under a restrictive licence issued by the Essential Services Commission of South Australia (ESCOSA), which precludes other service providers. This restriction on competition exists because it would be inefficient to have more than one network in the same geographic location. Competition in the provision of network services would not be in the interests of customers because electricity prices would have to be higher, reflecting the higher costs of having to build and maintain more than one distribution network. As competition is absent, we apply the most prescriptive form of regulation to network services—direct control.

A distributor's broad customer base uses network services through a shared network, provided by distributors under monopolistic conditions. Therefore, we classify network services as standard control services so distributors recover the cost of providing network services from across their broad customer base.

Similar to network services, standard connection services²⁷ are provided on a routine basis and are currently classified as standard control. SA Power Networks is the only provider of standard connection services. A standard (or basic) connection is a connection or an alteration which involves minimal or no augmentation (no extension or upgrade) of SA Power Networks' distribution network. It is provided on a 'standard' or routine basis. This is different to non-standard connection services which require an augmentation. Because standard connection services are not contestable in SA, we consider that these services should be classified as standard control.

²⁷ Connection services are sometimes referred to as basic or non-basic connection services.

We propose classifying type 5 and some type 6 metering services and exceptional large customer metering services (for types 1 to 4 meters) as alternative control services. Therefore, we set charges to allow distributors to recover the full cost of such services from customers that use them. Doing so will mean small customers will pay for metering services they actually use.

Sitting between direct control and unregulated services, is the negotiated service classification. Negotiated service terms and 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 non-standard connection services, should be classified as negotiated services.

In summary, with the exception of a number of metering related services, we consider there is insufficient evidence to change the classification for distribution services from that applied in the 2010–15 regulatory control period.

1.2 AER's assessment approach

The rules allow us to group distribution services when classifying them. This means we may classify a class of services rather than specific services. This provides distributors with flexibility to alter the exact specification (but not the nature) of a service during a regulatory control period. Where we make a single classification for a group of services, the classification applies to each service in the group.

When deciding whether to classify services as either direct control or negotiated, or to not classify them, the rules require us to have regard to the 'form of regulation factors' set out in the NEL.²⁸ We have reproduced these at appendix A. They include the presence or extent of barriers to entry by alternative providers and whether distributors possess market power in provision of the services. The rules also require us to consider the previous form of regulation applied to services and the desirability of consistency with the previous approach and any other relevant factor.²⁹

For services we propose to classify as direct control services, the rules require us to have regard to a number of factors.³⁰ These include the potential to develop competition in provision of a service and how our classification may influence that potential.³¹ Also, whether the costs of providing the service are attributable to a specific person and the possible effect of the classification on administrative costs.³²

The rules also provide that in classifying a direct control service previously regulated, unless a different classification is clearly more appropriate, we must:³³

²⁸ NER, clause 6.2.1(c); NEL, s. 2F.

²⁹ NER, clause 6.2.1(c).

³⁰ NER, clause 6.2.2(c)

³¹ NER, clause 6.2.2(c)(1).

³² NER, clause 6.2.2(c)(1) and NER, clause 6.2.2(c)(5)

³³ NER, clause 6.2.2(d).

- not depart from the previous classification (if the services have been previously classified), and
- if there has been no previous classification—the classification should be consistent with the previously applicable regulatory approach.

1.3 Reasons for AER's proposed approach

This section sets out our proposed approach for classification and reasons. In turn, this section deals with:

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

1.3.1 Network services

Distributors provide network services over a shared distribution network to all customers connected to it.³⁴ Customers use or rely on network services on a daily basis. Examples include the construction and maintenance of the shared network.

We propose to classify network services as direct control services and further, as standard control services. We received no submissions on our preliminary position for the classification of network services.

SA Power Networks holds an electricity distribution licence.³⁵ This licence is the only distribution licence currently issued for SA. Therefore, as the sole holder of the licence, SA Power Networks has an obligation to operate, maintain and protect its supply network.³⁶ Only SA Power Networks can provide network services that relate to the safe and reliable conveyance, and controlling the conveyance, of electricity through the distribution network. Further, consumers cannot source network services from other service providers.

We consider that the current licencing arrangement, whereby SA Power Networks is the only holder of a distribution licence, is a regulatory barrier preventing third parties from providing network services in South Australia.³⁷ Therefore, we propose to classify network services as direct control services.

We must further classify direct control services as either standard control or alternative control services.³⁸ For the following reasons we propose to retain the current classification of network services as standard control services:

- There is no opportunity to develop competition in the market for network services.

³⁴ NER, chapter 10, definition of 'network service'.

³⁵ 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.

³⁶ Electricity Distribution Licence, condition 2.1.

³⁷ NEL, s. 2F(a)(d).

³⁸ NER, clause 6.2.2(c).

- 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.

1.3.2 Connection services

In the 2010–2015 regulatory control period, SA Power Networks offered two broad types of connection services—standard and non-standard connections. A standard connection is a connection or an alteration which involves minimal or no augmentation (no extension or upgrade) of SA Power Networks’ distribution network. Standard connection services are currently classified as standard control services. Non-standard connection services require an augmentation. Non-standard connection services are currently grouped under the non-standard network services group and classified as negotiated services.

Standard connection services

Our proposed approach is to classify basic connection services as standard control services. We received no submissions on our preliminary position for the classification of basic connection services.

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

- residential customers (no extension or upgrade required)³⁹
- 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 provides standard 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 and therefore we consider that we should directly regulate the price of these services.

For the following reasons we consider the current standard control classification for standard connection services is appropriate:

- There is little, if any, prospect for competition in the market for standard connection services. That is, we are not aware of any South Australian Government initiatives to introduce contestability for connection services in the next regulatory control period. Therefore, our classification will not influence the potential for competition.

³⁹ NER, chapter 5A, A1.

- There would be no material effect on administrative costs to us, SA Power Networks, users or potential users. This is because a standard control classification for standard connection services is consistent with the current regulatory approach.
- We classify standard connection services in Queensland, South Australia and Tasmania as standard control services.⁴⁰
- 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 standard connection service where no such costs are required) require the requesting customer to make a capital contribution. This is discussed in the non-standard connection services section below.

For the above reasons, we consider retaining the current classification of standard control for standard connection services is justified.

Non-standard connection services

Our proposed approach is to classify non-standard connection services as negotiated services. We received no submissions to our preliminary position paper on the classification of non-standard connection services.

Unlike standard connection services, non-standard connection services are connection services that require an augmentation or significant alteration to the network. In most instances, non-standard 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 the requesting customer is required to make a capital contribution. In SA, non-standard connection services are contestable. That is, customers may choose to have the service performed by an alternative service provider.

Non-standard connection services are currently classified as negotiated services. When customers choose SA Power Networks to perform this service, the price is set by negotiation between the 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 change our classification approach to direct control would be significant. Forecasting the costs for this type of connection service would be complex, as the circumstances of individual customers requesting these services are variable. For example, the location and distance from the closest network infrastructure, and the connection characteristics desired by the customer. That customers may choose an alternative provider to design and construct the connection assets and associated work provides customers with countervailing power when negotiating with SA Power Networks.⁴¹ This gives further weight to retaining the current classification.

In classifying connection services, other than the factors set out in the rules,⁴² we have considered chapter 5A of the rules and its connection charge guideline (connection guideline).⁴³ The purpose of

⁴⁰ 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.

⁴¹ AER, *SA 2010–15 F&A Preliminary position*, pp. 29–31.

⁴² NER, clauses 6.2.1 and 6.2.2.

chapter 5A and the connection guideline is to provide a framework and charging principles for new connections or connection alterations.⁴⁴ 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 it. 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 services 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. Our 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 propose not to change the current classification for non-standard connection services.

1.3.3 Metering services

All electricity customers have a meter that measures the amount of electricity they use.⁴⁵ However, not all customers have the same type of meter. There are different types of meters which each measure electricity usage in different ways.

Type 1 to 4 meters are generally provided to large customers who consume greater than 160 megawatt hours (MWh) of electricity per annum. However, type 4 meters include 'smart meters' used by small commercial and residential customers. Clause 7.2.3(a)(1) of the rules provides that provision of these types of meters is contestable.

SA Power Networks is the monopoly provider of type 5 and 6 meters.⁴⁶ 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.⁴⁷

A brief description of the functionality of different meter types is set out in Table 3.

⁴³ AER, *Connection charge guidelines for electricity retail customers, under Chapter 5A of the National Electricity Rules*, June 2012.

⁴⁴ AER, *Connection charge guidelines for electricity retail customers, under Chapter 5A of the National Electricity Rules*, June 2012, p. 29.

⁴⁵ All connections to the network must have a metering installation (NER, clause 7.3.1A(a)).

⁴⁶ SA Power Networks is the 'responsible person' for type 5, 6, and 7 metering installations (NER, clause 7.2.3(a)(2)).

⁴⁷ Interval meters record electricity usage every 30 minutes.

Table 3: Description of different types of meters

Metering type	Description
Type 1 to 4 meters	Smart meters generally provided to large customers who consume greater than 160 megawatt hours (MWh) of electricity per annum. Have the capability to record time of use of energy and are read remotely.
Type 5 meters	Manually read interval meters with capability to record time of use of energy.
Type 6 meters	Manually read accumulative meters which simply record total electricity usage over a period of time. Currently the default meter type for households and other small consumption users.
Non-standard type 6 import and Export meters	Accumulative meters with generally the same functionality as standard type 6 meters but able to differentiate between imported and exported energy flows. Generally provided to users with small embedded generators (Solar Photovoltaic units) to measure energy exported to the grid.
Type 7 meters	Type 7 meters are unmetered connections which do not measure the consumption of electricity. Examples include streetlights or traffic lights. Usage at a type 7 meter connection is estimated using formulae and standard data.

Source: AER

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 scheduled 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.

In the 2010–2015 regulatory control period, the provision of metering services such as maintenance, repair and scheduled reading for type 6 meters was unbundled from other metering services such as energy data and storage services and metering investigation. These services are currently classified as alternative control services.

We currently classify type 1 to 4 metering services provided by SA Power Networks as negotiated. However, two exceptional cases of large customer metering services are classified as alternative

control services, for legacy reasons—we discuss these further below.⁴⁸ Type 5 metering 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).⁴⁹ Type 7 metering is currently classified as standard control.

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

- type 1 to 5 meters – negotiated services
- avoidable type 6 metering services – alternative control services
- fixed component of type 6 metering service – standard control services
- non-standard type 6 import and export PV meters – negotiated services
- type 7 – standard control services

We propose changing to alternative control the above classification for:

- the fixed component of type 6 metering
- non-standard type 6 import and export PV metering.

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 4.

⁴⁸ AER, *Final framework and approach paper ETSA Utilities 2010–15*, p. 10.

⁴⁹ NER, clause 7.2.3(a)(2).

Table 4: Proposed approach to classifying metering services

Metering service	AER's proposed approach
Type 7 metering	Standard control
Type 6 energy data services (except the scheduled meter read service)	Alternative control
Unscheduled meter reading – non-chargeable	Alternative control
Metering investigation – type 6	Alternative control
Maintaining and repairing meters and load control equipment – type 6	Alternative control
Type 6 meter installation	Alternative control
Type 6 meter provision	Alternative control
Scheduled meter reading – type 6	Alternative control
Non-standard type 6 import and export PV metering services	Alternative control
Exceptional large customer metering services (types 1-4 installed prior to 1 July 2000)	Alternative control
Type 5 metering	Alternative control
Type 1 to 4 metering	Negotiated
Meter testing at the request of the customer	Negotiated

Source: AER

Our reasons follow.

Type 1 to 4 metering services

Our proposed approach is to classify type 1 to 4 metering services as negotiated. We received no submissions on our preliminary position on this issue.

Type 1 to 4 metering services are contestable in South Australia.⁵⁰ For this reason, we propose to classify these as negotiated services. This is consistent with our current regulatory approach.

We note that there are two exceptional cases of type 1 to 4 meters currently classified as direct control and alternative control services, 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
- customers consuming more than 750 MWh per annum who have type 1 to 4 metering installations provided prior to 1 July 2005.

⁵⁰ Industrial and large customers may use types 1 to 4 meters. These meters are already open to competition and are not regulated by us (NER, clauses 7.2.3(a)(1) and 7.3.1.A(a)).

The circumstances for these customers have not changed and to accommodate existing contractual arrangements we propose to maintain the current classification for these services.

Type 5 metering services

Our proposed approach is to classify type 5 metering connection services as alternative control services.

Type 5 metering services are currently not contestable but to some degree experience competition from alternative providers of type 4 metering services. Our preliminary position was to retain the classification of the services as negotiated services. There has been no significant change in the market until the recent proposal by the SA Department for Manufacturing, Innovation, Trade, Resources and Energy (DMITRE) to make type 5 meters the default meter type for new and replacement meters for small customers with an opt-out mechanism.⁵¹ This proposed change in policy was released after our preliminary position and, if implemented, is likely to increase the penetration of type 5 meters in the 2015–20 regulatory control period.

We understand DMITRE intends to implement its new policy as part of a contestable framework, consistent with the metering contestability rule change the SA Government committed to through Council of Australian Governments (COAG). Under the new policy, if a meter is replaced with a 'smart ready' meter, it would be on a competitive basis. Competition would be provided under the proposed contestability rule change.⁵²

We consider that if this policy is implemented, type 5 metering services will be open to competition. Classifying type 5 meters as a negotiated service will better facilitate competition, compared to alternative control. However, we acknowledge the possibility that the SA Government's final policy may impose an obligation on SA Power Networks to provide the service. In this scenario, SA Power Networks will remain the monopoly service provider but in an expanded market due to the increase in the number of type 5 meter installations.

We consider it is appropriate to reclassify type 5 meter services from negotiated to alternative control because:

- the uncertainty of the policy outcome may mean there is less competitive pressure on SA Power Networks
- it offers greater scrutiny on the cost of providing the service
- it is consistent with the classification in other jurisdictions
- it does not hinder SA Power Networks' ability to compete with other service providers if the service becomes contestable under DMITRE's proposed policy changes. This is because SA Power Networks may charge less than the regulated price cap to remain competitive.

Classifications must be as set out in this final F&A unless we consider that unforeseen circumstances justify a different approach.⁵³ We will release our preliminary decision for SA Power Networks' 2015–2020 distribution determination in April 2015. This provides us with a further opportunity to reconsider this issue when we have a clearer understanding of the SA Government's policy in relation to type 5 meters.

⁵¹ DMITRE, *South Australian Policy for New and Replacement Electricity meters, Discussion Paper*, January 2014, pp. 1–3.

⁵² DMITRE, *South Australian Policy for New and Replacement Electricity meters, Discussion Paper*, January 2014, pp. 1–3.

⁵³ NER, clause 6.12.3(b).

Origin submitted that type 5 metering services should be classified as alternative control, because:⁵⁴

- DMITRE recently proposed that type 5 meters be installed as new and replacement meters. Type 5 metering services can only be provided by SA Power Networks.
- Although type 4 meters (as a substitute to type 5) should exercise some pressure on the price for type 5 metering services, this may not be effective in practice.

In these circumstances, we agree with Origin that the market for type 4 meters may not be sufficiently developed to offer competitive pressure on the pricing of type 5 meters. Consequently, the alternative control service classification is clearly more appropriate.

SA Power Networks submitted that type 5 meters should be reclassified from negotiated to alternative control due to the SA Government's policy for new and replacement meters. If type 5 meters remained classified as negotiated, SA Power Networks would be obliged to first negotiate with each customer before it installed any type 5 meters. SA Power Networks submitted that this adds significant costs to providing the service.⁵⁵ We consider that in a competitive environment, the tariff level and the impact it has on the up take of the service are determined by the market and any relevant legislation. These are not factors we consider for the purpose of service classification.

Therefore, our proposed approach is to reclassify type 5 metering services from negotiated to alternative control.

Type 6 metering services

Consistent with our preliminary position, our proposed approach to classification of type 6 metering services are set out in Table 5 below.

Table 5: 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 scheduled 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

⁵⁴ Origin, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks, Regulatory control period commencing 1 July 2015*, 13 February 2014, pp. 1–2.

⁵⁵ Origin, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks, Regulatory control period commencing 1 July 2015*, 13 February 2014, pp. 1–2.

After considering submissions from stakeholders we propose to retain the current classification for type 6 metering services, except:

- type 6 energy data services (excluding the quarterly meter read service)
- unscheduled meter reading – non-chargeable
- metering investigation.

We propose to reclassify these type 6 metering services from standard control to alternative control. We consider this will provide customers with more transparent costing information for these services. This will in turn assist customers to make informed choices should future rule changes allow third parties to provide these services.

As outlined in our preliminary positions F&A⁵⁶ we propose to make an additional change to the classification of type 6 metering services by separating the meter provision service into two services—meter installation and meter provision. Meter installation covers the on-site connection of a meter at a customer's premises. Meter provision 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. Therefore, it is appropriate to classify this as a negotiated service.

Classifying metering services as set out above reflects that the costs of providing different aspects of 'standard' small customer metering services are, or are not, directly attributable to a specific customer. We consider our proposed classification approach will promote the development of competition in the small customer metering market. Our classification approach is supported by submissions from Origin and Vector Limited.⁵⁷

SA Power Networks supported the classification of meter reading and data collection as alternative control. However, SA Power Networks submitted that other systems and capabilities would still be required by SA Power Networks even if it no longer undertook any meter provision services and these should be classified as standard control.⁵⁸ We agree that costs incurred in the provision of type 6 meter data services should be allocated to this alternative control service. Costs incurred by SA Power Networks in providing network services may be allocated to those standard control services. SA Power Networks' allocation of costs to the different types of services it provides should be consistent with its approved Cost Allocation Method.

SA Power Networks further submitted that the current form of cost recovery is a significant barrier to contestability in the metering market. Further, that exit charges also hinder the SA Government's

⁵⁶ AER, *Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, December 2013, p. 30.

⁵⁷ Origin, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 13 February 2014, p. 1; Vector Limited, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 19 February 2014, p. 2.

⁵⁸ SA Power Networks, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 19 February 2014, pp. 3–4.

desire for innovative service offers to be provided to customers.⁵⁹ To mitigate these barriers, SA Power Networks suggested the following options:

- classify the exit fee as alternative control and recover the fee through meter tariffs paid by all other customers using SA Power Networks' alternative control metering services
- classify existing type 6 meters as standard control and accelerate their depreciation
- classify all standard meter provision as standard control and recover the costs from all customers through distribution use of system (DUOS).

Our proposed classification approach does not provide for the manner in which the costs for transferring from a type 6 meter are recovered from customers. We will further consider the options submitted by SA Power Networks as part of our distribution determination. We understand the SA Government's metering policy will at that time be finalised. We also expect that more information on existing type 6 meters will then be available to us.

Non-standard type 6 import and export meters

Our proposed approach is to reclassify non-standard type 6 import and export (I/E) metering services from negotiated to alternative control.

SA Power Networks is currently the monopoly service provider for non-standard type 6 I/E PV meter services. In our preliminary positions paper we considered the potential to reclassify this service as alternative control, but highlighted a number of disadvantages of this approach, including:

- increased administrative costs for SA Power Networks and us
- introduction of forecasting risks—particularly for future PV take up rates
- pricing inflexibility, as it does not account for cost reductions from advances in metering technology because the service price is fixed for five years.

SACOSS submitted that non-standard type 6 I/E PV meter services should not be classified as negotiated because the service is not contestable. Further, that the current installation cost of type 6 I/E PV meters of \$315, although a significant reduction from \$440 initially charged in 2010, appears high.⁶⁰ We consider this issue warrants further investigation. By reclassifying the service as alternative control, we will facilitate a close assessment of the service price in the context of our distribution determination.

We accept that, under an alternative control classification, SA Power Networks may have less flexibility to pass on cost savings to customers from technological advancements. It may also limit opportunity for customers to negotiate a better outcome than the regulated price. However, the potential rule change to expand competition in metering, which may include type 6 I/E PV meters, will to some degree mitigate these disadvantages. This is because customers would be able to choose between SA Power Networks and alternative service providers. This approach will add to the administrative costs of SA Power Networks and us, but some of these costs will be balanced out by

⁵⁹ SA Power Networks, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 19 February 2014, pp. 4–5.

⁶⁰ The installation cost of I/E PV meter is \$ 314.50 for existing standard connection and \$679.80 for all new and existing non-standard connections.

synergies from classifying all standard and non-standard type 6 metering service as alternative control services. SACOSS supported this approach.⁶¹

SA Power Networks submitted that many costs associated with non-standard type 6 I/E PV meters are currently not solely allocated to negotiated services. Rather, costs are recovered through a combination of up-front charges (meter installation classified as negotiated services) and on-going metering tariffs (asset costs, reading and maintenance classified as alternative control). SA Power Networks further submitted that we should define type 6 metering services to make clear they include the standard component of import/export metering services. Our proposed approach to classify all non-standard type 6 I/E PV meter services as alternative control will address this issue.⁶²

Type 7 metering services

We proposed to classify type 7 metering services as standard control, consistent with our current classification approach.

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, SA Power Networks estimates streetlight usage using the total time the lights were on, the number of lights in operation and the light bulb wattage.

SA Power Networks is the monopoly service provider of type 7 metering services in South Australia. We consider type 7 metering services could be unbundled, though the potential benefits of doing so appear to be minimal. The avoidable cost component of type 7 metering services is likely to be small relative to total service costs, relating only to energy data services. Therefore, we do not consider there would be a net benefit from unbundling charges for these services from the distribution use of system tariff. For this reason, we propose to classify type 7 metering services as standard control services, consistent with our current classification. This is also consistent with our classification approach in other jurisdictions.

Citelum Australia submitted that it disagrees with our proposed classification of type 7 metering services as standard control, because it will restrict competition for the provision of these services.⁶³

In response to the Citelum Australia submission, and in the context of the F&A process, we note that our role in service classification only determines the manner in which SA Power Networks recovers the costs associated with the distribution services it provides – it does not determine the contestability of these services.⁶⁴ For example, our classification of a distribution service as a direct control service does not make SA Power Networks the exclusive monopoly provider of the service. Likewise, our classification of a distribution service as a negotiated distribution service does not make the service contestable and open to supply by providers other than SA Power Networks. Contestability is determined by legislation, the rules, or other instruments, and is beyond our control. Contestability is, however, one of the factors we must consider in classifying services. We do have a role in

⁶¹ SACOSS, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 18 February 2014, pp. 4–5.

⁶² The classification of distribution services in the 2015–20 regulatory control period is set out in attachment B. Alternative control services for standard small customer metering services is defined in B.4.

⁶³ Citelum Australia, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 13 February 2014, p. 7.

⁶⁴ Contestability relates to whether or not a service is permitted by the laws or other regulatory instruments of the relevant jurisdiction to be provided by more than one distributor.

determining the negotiated distribution service criteria and framework for negotiation. We will consider these matters in the regulatory determination process for SA Power Networks.

Trans-Tasman Energy Group submitted that the description of the type 7 metering services provided by SA Power Networks can be enhanced. It proposed that the description include a requirement for SA Power Networks' metering procedures to comply with Part A and B of Australian Energy Market Operator's 'Metrology procedure: National Electricity Market'.⁶⁵ We consider the issue raised by Trans-Tasman Energy Group is outside the scope of our service classification approach.

1.3.4 Public lighting services

We propose to classify public lighting services as negotiated services, consistent with our current classification approach.

We consider the existing arrangements are operating well for new installations of public lighting. SA Power Networks and some customers have had difficulty in agreeing to terms and conditions (including price) for existing public lighting assets. We are also aware of a potential dispute between some public lighting customers and SA Power Networks. However, the existence of a potential dispute does not in itself mean that the current classification is not appropriate. Submissions from the Local Government Association of SA (LGA) and the SA Department of Planning, Transport and Infrastructure (DPTI) supported continuing the current classification of public lighting as a negotiated service.⁶⁶ This approach was also supported by other stakeholders.⁶⁷

Citelum Australia also supported the classification we proposed but submitted that SA Power Network's pricing of the service hinders competition. Citelum Australia's submission raised a number of structural issues around service contestability and pricing, including the allocation of risk between SA Power Networks and other parties. These matters are outside the scope of service classification. Rather, they relate to the negotiating distribution service criteria and negotiating framework, which support the negotiation process. We will consult on these in the context of our distribution determination.

For the above reasons, we propose to retain the current negotiated service classification for public lighting.

1.3.5 Non-standard network services

We propose to classify non-standard network services as negotiated services.⁶⁸

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:

⁶⁵ Trans-Tasman Energy Group, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 10 February 2014, p. 1.

⁶⁶ LGA, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 12 February 2014, p. 1; DPTI, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 14 February 2014, p. 1.

⁶⁷ Citelum Australia, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 9 January 2014, p. 3; Trans-Tasman Energy Group, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 10 February 2014, p. 1.

⁶⁸ These services are listed in sections B.7 to B.16 of appendix B.

- 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
- 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-standard 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 services,⁶⁹ we propose to classify them as negotiated. The remaining services⁷⁰ 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 to entry preventing third parties providing these services. For the following reasons we propose to classify these services as negotiated services:⁷¹

- 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.
- the elasticity of demand and the substitutable nature of these services are greater for these services compared to core distribution services.
- although legislation currently does not allow these services to be contestable, potential to develop competition exists if legislative barriers are 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 the 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.⁷²

For the above reasons, our proposed approach is to continue to classify non-network services as negotiated services.

The South Australia Department of Planning, Transport and Infrastructure (DPTI) made a submission supporting our preliminary position for the classification of non-standard network services. However, DPTI submitted that the definition of 'asset relocation services' is unclear. DPTI suggested alternative wording to be clear that SA Power Networks is bound to carry out the services under the negotiated service principles, criteria and the framework for negotiation.

In response to DPTI's submission, we consider that the current definition of 'asset relocations' would benefit from additional clarity that the negotiated services framework applies to all asset relocations.⁷³ We have therefore amended the definition at appendix B.⁷⁴

⁶⁹ Those listed as competitively available on p. 32 (dot points 1–12).

⁷⁰ Those listed as 'other non-standard services' on p. 33 (dot points 1–14).

⁷¹ AER, *Final framework and approach ETSA Utilities 2010–2015 regulatory control period*, pp. 28–32.

⁷² NER, clauses 6.2.1(d) and 6.2.2(d).

⁷³ Asset relocations are currently defined as 'Moving mains, services or meters forming part of the distribution system'.

⁷⁴ See definition B.13 a. in appendix B.

1.4 Conclusion

In summary, we propose to group and classify SA Power Networks' distribution services as set out in Tables 6 and 7.

Table 6: Proposed classification of SA Power Networks' 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	Connection services at mandated standard	Connection services at higher (or lower) than mandated standard
	New or upgraded connection services (to the extent the user is not required to make a financial contribution)	New or upgraded connection services (to the extent that the user is required to make a financial contribution)
Metering services	Small customer standard meter provision and energy data services (type 5 and 6 metering installation services and meter provision services)	
	Non-standard type 6 import and export photovoltaic metering services Unmetered metering services (type 7 metering installations) Two 'exceptional cases' of large customer metering services (type 1 to 4 meter provision services), being: - 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.	Meter testing at the request of the customer. Large customer meter provision and energy data services (type 1 to 4 metering installations)
Public lighting services	Nil	Provision, operation and maintenance of public lighting assets Lamp replacement 'Energy only' services
Non-standard network services	Nil	Remaining services listed in appendix B as negotiated distribution services, which includes: - provision of stand-by or temporary supply - asset relocations - temporary disconnections - provision of copies of various codes - embedded generation services

Source: AER

Table 7: Proposed classification of SA Power Networks' direct 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 services)	<p>Standard small customer type 5 and 6 metering services</p> <p>Non-standard type 6 import and export photovoltaic metering services</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 decision on the 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 2015–20 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.

The control mechanism in SA Power Networks' regulatory proposal must be as set out in this F&A. We can 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.⁷⁵

2.1 AER's decision

Our decision is to apply the following forms of control in the 2015–20 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 form of control mechanism⁷⁶
- the basis of the control mechanism⁷⁷
- 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 factor⁷⁸ and applicable adjustment

⁷⁵ NER, clause 6.12.3(c).

⁷⁶ NER, clause 6.2.5(b).

⁷⁷ NER, clause 6.2.6(a).

⁷⁸ 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.⁷⁹ 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 services⁸⁰

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 total revenue allowed for each year of the regulatory control period. Distributors must then recover revenue equal to or less than the total revenue. 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 total revenue. 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 total revenue in future years. This operation occurs through an 'overs and unders' account, whereby any over-recovery (under-recovery) is deducted from (added to) the total revenue in future years.

- tariff basket price control (WAPC)

A weighted average price cap (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 total revenue 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 total revenue 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.

We consider that a schedule of fixed prices or caps on the prices of individual standard control services is not appropriate. This is because we consider these direct price control mechanisms do not

⁷⁹ The applicable adjustment factor captures the revenue adjustments required to account for the outcome of varies 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.

⁸⁰ 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.

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.⁸¹

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

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 wants⁸²
- 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

⁸¹ NER, clause 6.2.6(a).

⁸² 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.

- 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 a reasonable opportunity to recover at least efficient costs.⁸³ We also consider that a control mechanism should limit revenue recovery above such costs. Revenue recovery above efficient costs results in unnecessary higher prices for consumers. Further, a distributor 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.⁸⁴

2.2.2 Alternative control services

In determining a control mechanism to apply to alternative control services, we will consider the factors in clause 6.2.5(d) of the rules:

- the potential for competition to develop in the relevant market and how the control mechanism might influence that potential
- the possible effects of the control mechanism on administrative costs of us, the distributor and users or potential users

⁸³ NEL, s. 7A (2).

⁸⁴ Peak demand is generally referred to as the maximum load on a section of the network over a very short time period.

- 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 that another relevant factor is the provision of cost reflective prices. Efficient prices or cost reflectivity allows consumers to compare the cost of providing the service to their needs and wants. Cost reflective prices also allow distributors to make efficient investment and demand side management.

We must state what the basis of the control mechanism is in our distribution determination.⁸⁵ This may utilise elements of Part C of chapter 6 of the rules with or without modification. For example, the control mechanism may use a building block approach or incorporate a pass-through mechanism.⁸⁶

2.3 AER's reasons — control mechanism and formulae

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

Price instability within the regulatory period can occur under all forms of control mechanisms. This is because the rules require various annual price adjustments regardless of the control mechanism. This can be managed under the revenue cap through the application of tolerance limits on unders and overs that lowers price volatility. We consider that the revenue cap form of control by itself offers limited incentives for distributors to price efficiently. However, this issue can be address when network pricing arrangements are in place to enable distributors to set efficient and flexible network tariffs. These arrangements are currently under consideration by the AEMC as part of the rule change proposal by COAG Energy Ministers for distribution network pricing arrangements.⁸⁷

The details of our reasoning are set out below.

⁸⁵ NER, clause 6.2.6(b).

⁸⁶ NER, clause 6.2.6(c).

⁸⁷ AEMC, *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, Consultation Paper*, 14 November 2013.

2.3.1 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, in isolation under a revenue cap, distributors' revenues are fixed over the regulatory control period. As a result, there is no additional incentive for them to price efficiently. We consider this issue can be address through network pricing arrangements to enable distributors to set efficient and flexible network tariffs. These arrangements are currently under consideration by the AEMC as part of the rule change proposal by COAG Energy Ministers for distribution network pricing arrangements.⁸⁸

Weighted average price cap

Distributors under a WAPC can retain revenue recovered above the expected revenue we estimate. 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 per unit 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
 - 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.

⁸⁸ AEMC, *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, Consultation Paper*, 14 November 2013.

- 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,⁸⁹ 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. As an alternative, we reviewed tariff outcomes of other distributors in Victoria and NSW which have been operating under the same incentive created by the WAPC for a longer period. The details of the analysis are included in the Stage 1 of the NSW F&A. We concluded based on the analysis that the WAPC has not provided an incentive for, or resulted in, increased pricing efficiency. The analysis revealed that there were inefficiencies related to the widespread use of inclining block tariffs and the low utilisation of tariffs.⁹⁰

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

Origin supported the continuation of the current WAPC form of control but acknowledged a WAPC has not led distributors to price efficiently. Origin suggested that a hybrid revenue cap should be adopted, such as a revenue cap adjusted within the period by cost drivers such as customer numbers and peak demand and increasing the fixed component in network prices relative to volumetric components.⁹¹

⁸⁹ 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.

⁹⁰ AER, *Stage 1 Framework and approach paper Ausgrid, Endeavour Energy and Essential Energy, Appendix F: Revenue recovery*, March 2013, pp. 105–106.

⁹¹ Origin, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 13 February 2014, pp. 2–3.

In response to Origin's submission, we have considered in our preliminary position the application of a hybrid revenue cap for SA Power Networks. Under the hybrid revenue cap, regulated revenue is adjusted within the regulatory period to account for deviations from forecast cost drivers that is, customer numbers and peak demand.⁹² We concluded that the design enables distributors' revenues to align more closely to the cost drivers compared with a revenue cap. However, the relationship between cost drivers and expenditure by SA Power Network is complex and it may change from year to year. It is difficult to develop an effective revenue function under a hybrid revenue cap which allows a relatively simple mechanical process to adjust the revenue requirement based on cost drivers. An alternative approach is to undertake a detailed review on cost drivers and expenditure to 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 the above 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. 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. On balance we consider that higher administrative costs to distributors and us under a hybrid revenue cap outweigh its potential benefits.

2.3.3 Existing regulatory arrangements

We consider that consistency across regulatory arrangements for relevant services is generally desirable. We consider that this factor 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.

2.3.4 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. Consistent regulatory arrangements need to be weighed against the other factors under clause 6.2.5(c). Pursuing the other factors produces outcomes that better achieve the National Electricity Objective and are consistent with the revenue and pricing principles. The application of revenue cap for SA Power Networks is consistent with our position for Queensland, Tasmania and NSW distribution network businesses.

2.3.5 Revenue recovery

We consider that a revenue cap provides a higher 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.

⁹² AER, *SA 2010–15 F&A Preliminary position*, November 2008, p. 46.

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 by SA Power Networks under the WAPC because of its recent introduction. As an alternative, we reviewed tariff outcomes of other distributors in Victoria and NSW which have been operating under the same incentive created by the WAPC for a longer period. This analysis is included in the NSW stage 1 F&A. The analysis revealed that NSW and Victorian distributors were able to recover revenue systematically above forecast.⁹³

SACOSS submitted that it recognises the rationale for pursuing more cost reflective pricing and the importance of a revenue cap in achieving this. However, SACOSS submitted that the change to a revenue cap must also be seen as significantly de-risking the role of SA Power Networks because under the revenue cap customers take the volume risk. SACOSS submitted that it only supported such a change on the basis that this reallocation of risk is adequately reflected in the weighted average cost of capital (WACC) set by us for the upcoming regulatory period.⁹⁴ In response to SACOSS's submission, the WACC is determined based on an efficient benchmark firm. Rule 6.5.2 of the NER states that:

the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider in respect of the provision of standard control services (the allowed rate of return objective).

Therefore, the volume risk will be considered as part of the overall assessment of risk for the provision of standard control services and factored into the determination of the rate of return for the efficient benchmark firm.

2.3.6 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.⁹⁵

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

⁹³ AER, *Stage 1 Framework and approach paper Ausgrid, Endeavour Energy and Essential Energy, Appendix F: Revenue recovery and Appendix E: Efficient pricing*, March 2013.

⁹⁴ SACOSS, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 18 February 2014, pp. 3–4.

⁹⁵ The form of control mechanism determines whether direct control services should be regulated by price or by revenue. It has less influence on pricing flexibility compared to side constraints and pricing principles. This is because a side constraint sets a quantitative limit on how much the weighted average revenue can increase for a tariff basket, while pricing principles set out the factors and principles the network business must satisfy when applying tariffs in the regulatory period. Both directly influence the flexibility for adjusting tariffs and tariff structures.

would be of increasing importance under likely changes to the pricing principles proposed by COAG Energy Ministers.

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.⁹⁶

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.⁹⁷ 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.^{98,99} 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.¹⁰⁰

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.

SA Power Networks supported altering the form of control from a WAPC to a revenue cap. SA Power Networks submitted that we have used different approaches to the overs and unders accounts in Tasmania and Queensland and as a principle, any tolerance mechanism should seek to allow recovery of allowed revenue for the period in that period. It should not be designed in a way that revenues are deferred well into the subsequent period.¹⁰¹ We accept that the design of the unders and overs account should strike a balance between revenue recovery for network service provider and price stability for customers. We will consider this issue in the distribution determination stage.

⁹⁶ These include cost pass throughs, jurisdictional scheme obligations, tribunal decisions and transmission prices passed on to the distributors from the transmission network service providers.

⁹⁷ AER, *Queensland distribution determination 2010–11 to 2014–15*, May 2010, Appendix D.

⁹⁸ AER, *Final Distribution Determination Aurora Energy Pty Ltd 2012–13 to 2016–17*, April 2012, pp. 20–23.

⁹⁹ 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.

¹⁰⁰ 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.

¹⁰¹ SA Power Networks, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 19 February 2014, p. 5.

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. That is, any demand side management project 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.

After consideration of submissions from stakeholders, we maintain our preliminary position and 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.

2.3.7 Formulae for standard control services

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 paper.¹⁰² 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.¹⁰³

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

Revenue cap for standard control services (as determined by the post-tax revenue model)

$$(1) AR_t = AR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t)$$

Total allowed revenue (including adjustments for incentive payments and pass throughs etc.)

$$(2) TR_t = AR_t + I_t + B_t + C_t$$

The revenue cap requires that revenue in year t should be no greater than the sum of each price in year t multiplied by each quantity in year t. However, prices must be set in advance and we do not know at the relevant time what the quantities will be. Therefore, a forecast must be used. The difference between forecast and actual revenues will be added to the unders and overs account when it becomes known. We will decide on the forecasts of quantities as part of our annual compliance check taking into account the distributor's proposal.

¹⁰² NER, clause 6.8.1(b)(2)(ii).

¹⁰³ NER, clause 6.12.3(c1).

SA Power Networks is to demonstrate compliance with formulas (1) and (2) via the following expression in their initial and annual pricing proposals:

$$TR_t = \sum_{i=1}^n \sum_{j=1}^m p_{ij}^t q_{ij}^t \quad i = 1, \dots, n \text{ and } j = 1, \dots, m \text{ and } t = 1, \dots, 5$$

NOTE: in the event that a jurisdictional scheme/s is introduced then the revenue required for that scheme/s will be in addition to that specified in formula (2).

Where:

AR_t is the allowed revenue for regulatory year t. For the first year of the next regulatory control period, this amount will be equal to the smoothed revenue requirement for 2015–16 set out in the PTRM approved by us. The subsequent year's allowed revenue is determined by adjusting the previous year's allowed revenue for CPI and the X factor.

ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from December in year t–2 to December in year t–1. For example, for the 2015–16 year, t–2 is December 2013 and t–1 is December 2014 and in the 2016–17 year, t–2 is December 2014 and t–1 is December 2015 and so on.

X_t is the X factor for each year of the next regulatory control period as determined in the post-tax revenue model. Likely to also incorporate an annual adjustment for the return on debt. To be decided upon in the final decision.

TR_t is the total revenue allowable in year t.

I_t is the sum of incentive scheme adjustments in year t. 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.

C_t is the sum of adjustments likely to incorporate but not limited to pass through events and feed-in tariff payments that are not made under jurisdictional schemes. To be decided upon in the final decision.

p_{ij} 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.

Since our preliminary position paper, we have revised the formulae to allow for adjustments following changes in the next regulatory control period.

2.3.8 Alternative control services

Our decision is to apply a price cap to each individual alternative control services.

In our 2010 distribution determination, the variable components of the 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.

The alternative control services have been expanded to include type 5 metering services, non-standard import and export PV type 6 metering services, and all remaining components of type 6 metering services apart from metering investigation services requested by customers.

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 distributor 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 alternative control services that may occur when adjusting the relative price between the services.

Our decision 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 period¹⁰⁴
- 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 limited.

The details of our reasoning are set out in below.

Influence on the potential to develop competition

We consider that the control mechanism for alternative control services will not have a significant impact on potential competition development. We consider the primary influence on competition development will be the classification of services as alternative control services. Attachment 1 discusses classification.

Administrative costs

For type 6 metering services, 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 services is negligible because there will be no change to current reporting and modelling requirements.

We consider the classification of services and the basis of the form of control mechanism are the primary influences on administrative costs. We recognise the proposed change in classification of type 5 metering services and a change in control mechanism may result in some additional administrative costs. We consider these costs will largely be incurred in transitioning to the new control mechanism. We consider the changes will create greater cost transparency and reflectivity for

¹⁰⁴ NER, clause 6.2.5(b)(3).

these service charges to customers in a user-pays environment. We consider these benefits warrant a short term increase in administrative costs.

Existing regulatory arrangements

We consider consistency across regulatory control periods is generally desirable. However, we consider consistency across regulatory control periods should not be our primary consideration in determining a control mechanism in this instance. Our consideration of other factors in clause 6.2.5(d) of the rules leads us to the conclusion that a change in the current control formula from a WAPC to a pure price cap would lead to an overall outcome more consistent with the NEO and revenue and pricing principles than the other possible alternatives.

Desirability of consistency between regulatory arrangements

We consider consistency across jurisdictions is generally desirable but is not primary to our considerations in this instance. Desirability needs to be weighed against the other factors under clause 6.2.5(c) of the rules. Consideration of the other factors reveal outcomes that further the national electricity objectives and are consistent with the revenue and pricing principles.

Cost reflective prices

We consider that caps on the prices of individual services are more suitable than other control mechanisms for delivering cost reflective prices. Under caps on the prices of individual services, we will estimate the cost of providing each service and set the price at that cost. If competition develops within the period on some or all services, distributors will be able to compete by charging below the cap. However, unlike under a WAPC, distributors will not be able to compensate for such reductions by increasing the price on non-competitive services. This will enhance cost reflectivity on both competitive and non-competitive services.

SA Power Networks submitted that it does not support a price cap. SA Power Networks considered that a revenue cap (consistent with the form of control for standard control), or to a lesser extent a WAPC would mitigate the risk associated with forecasting metering volumes (where the fixed costs are independent of meter volume whereas the variable cost components are volume dependent). This would allow more flexibility to adjust prices within the different metering services offered compared to a pure price cap.¹⁰⁵ We agree that there is potential risk in revenue under recovery if volume for a service is lower than expected. This is because some fixed costs in providing metering services are independent of the volume. However, we consider the magnitude of the revenue risk is likely to be small and this risk can be largely addressed by allocating these fixed costs to standard control network services and recovered through DUOS. We will consider the allocation of costs in the distribution determination process.

After consideration of SA Power Networks' submission, we maintain our preliminary position to apply a price cap for each individual alternative control services.

2.3.9 Formula for alternative control services

We are required to set out our proposed approach to the formula that give effect to the control mechanisms for alternative control services in this F&A paper.¹⁰⁶ We must include the formula as set

¹⁰⁵ SA Power Networks, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 19 February 2014, p. 6.

¹⁰⁶ NER, clause 6.8.1(b)(2)(ii).

out below in our distribution determination, unless we consider that unforeseen circumstances justify departing from the formula as set out in the F&A paper.¹⁰⁷

Below is a proposed formula to apply to alternative control services where a price cap applies. We consider that the formula gives effect to the cap on the prices of individual services:

$$p_i^t = p_i^{t-1}(1 + \Delta CPI_t)(1 - X_i^t) + A_i^t$$

Where:

p_i^{t-1} is the cap on the price of service i in year t-1

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

ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1. For example, for the 2015-16 year, t-2 is December 2013 and t-1 is December 2014 and in the 2016-17 year, t-2 is December 2014 and t-1 is December 2015 and so on.

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

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

For the avoidance of doubt, when setting the prices for 2015-16, p_i^t are prices being set for year 2015-16 and p_i^{t-1} are prices from the year 2014-15.

¹⁰⁷ NER, clause 6.12.3(c1).

3 Incentive schemes

This attachment sets out our proposed position on the application of a range of incentive schemes to SA Power Networks for the next regulatory control period. Our 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 STPIS¹⁰⁸ provides a financial incentive to distributors to maintain and improve service performance. The STPIS aims to provide 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 customers¹⁰⁹ experiencing service below a predetermined level.¹¹⁰

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

¹⁰⁸ AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009.

¹⁰⁹ Except where a jurisdictional electricity GSL requirement applies.

¹¹⁰ 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.¹¹¹ 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.¹¹² 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.¹¹³

3.1.1 AER's proposed approach

Our proposed approach is 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 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 distributor's 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.¹¹⁴

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.¹¹⁵ The Australian Energy Market

¹¹¹ AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009, clause 2.2.

¹¹² AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009, clauses 2.5(d) and (e).

¹¹³ AER, *Final framework and approach paper, application of schemes, ETSA Utilities 2010–15*, November 2008, p. 60.

¹¹⁴ 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

¹¹⁵ AEMC, *Review on national framework for distribution reliability*, 27 September 2013.

Operator (AEMO) is currently conducting analysis on how willing consumers are to pay for improvements in network reliability.¹¹⁶ We consider there is likely to be inadequate time to review our national STPIS to incorporate the findings of these reviews before finalising our determinations for SA Power Networks.

3.1.2 AER assessment approach

The rules require us to have regard to several factors in developing and implementing a STPIS for SA Power Networks.¹¹⁷ These include:

- Jurisdictional obligations
 - consulting with the authorities responsible for the administration of relevant jurisdictional electricity legislation
 - checking 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 STPS are contained in our final decision for the national distribution STPIS.¹¹⁸

3.1.3 Reasons for AER's proposed approach

Our reasons for proposing to apply the STPIS to SA Power Networks in the next regulatory control period are set out below. Our distribution determination for SA Power Networks for the next regulatory control period will specify how we will apply the STPIS.

¹¹⁶ AEMO, *Value of customer reliability issues paper*, 11 March 2013; AEMC, *Advice on linking the reliability standard and reliability settings with VCR*, October 2013.

¹¹⁷ NER, clause 6.6.2(b).

¹¹⁸ AER, *Final decision: Electricity distribution network service providers Service target performance incentive scheme*, 1 November 2009.

Jurisdictional obligations

In South Australia, the Essential Service Commission of South Australia (ESCOSA) administers and monitors compliance with the distribution licence conditions. As required by the rules, we will consult with the ESCOSA and the Department for Manufacturing, Innovation, Trade, Resources and Energy, as jurisdictional authorities, on the implementation of the STPIS¹¹⁹ before finalising our distribution determination.

Our proposed approach to applying the STPIS for SA Power Networks does not intend to compromise SA Power Networks ability to comply with jurisdictional licence obligations or create duplication. We intend doing this by not:

- setting service performance targets lower than the minimum service requirements in the licence conditions; and
- 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.¹²⁰

Under the STPIS, 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 the Essential Services Commission Victoria and Essential Services Commission of South Australia.¹²¹ The distributors may propose an alternative VCR estimate, supported by details of the calculation methodology and research, in their regulatory proposals.¹²²

The AEMC recently conducted a review of distribution reliability outcomes and standards in the NEM, proposing a more significant role for the STPIS.¹²³ AEMO is currently reviewing current approaches to estimating VCR and it is unclear when AEMO will propose new VCR estimates. We may undertake a review of our national STPIS once these studies are complete. Any change to the STPIS would be

¹¹⁹ NER, clause 6.6.2(b)(1).

¹²⁰ NER, clause 6.6.2(b)(3)(vi).

¹²¹ 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.

¹²² AER, *Electricity distribution network service providers, Service target performance incentive scheme*, November 2009, p. 9.

¹²³ AEMC, *Draft report: Review of distribution reliability outcomes and standards*, 28 November 2012.

subject to the distribution consultation procedures in the rules.¹²⁴ We consider there is insufficient time to conduct a comprehensive review of the STPIS before SA Power Networks submits its proposal for the next regulatory control period in October 2014. Therefore our preliminary position was 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.¹²⁵ Our preferred approach is to base performance targets on the distributors' average performance over the past five regulatory years.¹²⁶ 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.¹²⁷ For SA Power Networks, 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.¹²⁸

In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.¹²⁹

¹²⁴ NER, Part G.

¹²⁵ NER, clause 6.6.2(b)(3)(iii).

¹²⁶ Subject to any modifications required under clauses 3.2.1(a) and (b) of the national STPIS.

¹²⁷ NER, clause 6.6.2(b)(3)(iv).

¹²⁸ NER, clause 6.6.2(b)(3)(v).

¹²⁹ Included in the distributor's approved forecast capex for the next period.

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 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. The interaction of the schemes is an important factor, also noted by some CCP members.¹³⁰ That is, the STPIS provides an incentive for distributors to maintain network performance given other incentives encourage them to defer or avoid network investment.

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.

Transitional issues

Under the current STPIS applying to SA Power Networks the major event days is approximately five days per year calculated based on the Box-Cox transformation and under the national scheme the number is approximately 2.5 days per year based on the Institute of Electrical and Electronic Engineers (IEEE) standard. SA Power Networks submitted that this will create transitional issues when recalculating targets for 2015–2020 and 2020–2025 because the targets are based on five years of actual performance.¹³¹

We acknowledge the difference in the calculation of major event days in the national distribution STPIS and the scheme currently apply to SA Power Networks. We will consider the application of a transitional arrangement to address this issue in the distribution determination process.

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 proposed approach 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 proposed approach

We propose applying our new EBSS¹³² to SA Power Networks for the 2015–20 regulatory control period.

¹³⁰ Consumer Challenge Panel discussion with AER staff on 5 March 2014.

¹³¹ SA Power Networks, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 19 Feb 2014, pp. 6–7.

¹³² AER, *Efficiency benefit sharing scheme*, 29 November 2013.

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.¹³³ We must also have regard to the following factors in developing and implementing the EBSS:¹³⁴

- 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.

3.2.3 Reasons for AER's proposed approach

We propose to apply our new EBSS¹³⁵ to SA Power Networks for the 2015–20 regulatory control period. The application of the scheme will provide incentives for SA Power Networks to spend efficiently and share the benefit of efficiencies with users. The scheme provides a continuous incentive for SA Power Networks to achieve efficiency gains in such a way that they will not benefit from inflating opex in any one year. This provides an incentive for SA Power Networks to reveal their efficient opex which, in turn, allows us to better determine efficient opex forecasts for future regulatory control periods.

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

In developing the new EBSS we had regard to the requirements under the rules, as set out in the scheme and accompanying explanatory statement.¹³⁶ 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.¹³⁷ Under the scheme SA Power Networks and consumers receive a benefit where SA Power Networks 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.¹³⁸ The EBSS provides a continuous incentive for SA Power Networks 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

¹³³ NER, clause 6.5.8(a).

¹³⁴ NER, clause 6.5.8(c).

¹³⁵ AER, *Efficiency benefit sharing scheme*, 29 November 2013.

¹³⁶ 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.

¹³⁷ NER, clause 6.5.8(a).

¹³⁸ NER, clauses 6.5.8(c)(3) and 6.5.8(a).

period for the length of the carryover period. This is regardless of the year in which it makes the gain or loss.¹³⁹

This continuous incentive to improve efficiency encourages efficient and timely opex throughout the regulatory control period, and reduces the incentive for SA Power Networks to inflate opex in the expected base year. This provides an incentive for SA Power Networks 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.¹⁴⁰ 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.

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.

¹³⁹ NER, clause 6.5.8(c)(2).

¹⁴⁰ NER, clause 6.5.8(c)(1).

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

(Example 1 continued)

Table 8 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 9 sums the discounted benefits to distributors and consumers from the bottom two rows of Table 8. As illustrated below, the benefits of the efficiency improvement are shared approximately 30:70 in perpetuity between the distributor and consumers.

Table 9 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.¹⁴¹ Where opex incentives are balanced with capex incentives, a distributor does not have an incentive to favour opex over capex, or vice-versa. The capital expenditure sharing scheme (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. That is, under both schemes, efficiency gains or losses are shared approximately 30:70 between distributors and consumers. 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:¹⁴²

- 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.¹⁴³ 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.¹⁴⁴

SA Power Networks submitted that it will work with the AER to reach agreement on appropriate exclusions from the EBSS at the determination stage.¹⁴⁵

3.3 Capital expenditure sharing scheme

Our position is to apply the CESS, as set out in our capex incentives guideline,¹⁴⁶ in the next regulatory control period to SA Power Networks.

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.

¹⁴¹ NER, clause 6.5.8(c)(4).

¹⁴² NER, clause 6.5.8(c)(5).

¹⁴³ 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.

¹⁴⁴ 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.

¹⁴⁵ SA Power Networks, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 19 February 2014, p. 7.

¹⁴⁶ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–10.

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.

We calculate the CESS payments taking into account the financing benefit or cost to the distributor of the underspends or overspends.¹⁴⁷ 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 proposed approach

Our position is to apply the CESS, as set out in our capex incentives guideline,¹⁴⁸ in the next regulatory control period to SA Power Networks.

3.3.2 AER's 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:¹⁴⁹

- make that decision in a manner that contributes to the capex incentive objective¹⁵⁰
- consider the CESS principles,¹⁵¹ capex objectives,¹⁵² 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 proposed approach

Our position is to apply the CESS, as set out in our capex incentives guideline,¹⁵³ in the next regulatory control period to SA Power Networks. We consider the application of the scheme will contribute to the capex incentive objective, capex criteria capex objectives and CESS principles. It

¹⁴⁷ 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.

¹⁴⁸ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–10.

¹⁴⁹ NER, clause 6.5.8A(e).

¹⁵⁰ NER, clause 6.5.8A(e).

¹⁵¹ NER, clause 6.5.8A(c).

¹⁵² NER, clause 6.5.7(a).

¹⁵³ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–10.

provides an incentive for SA Power Networks to spend efficiently and share the benefit of efficiencies with users.

SA Power Networks is 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.¹⁵⁴ The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.¹⁵⁵ 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.¹⁵⁶ We also developed the CESS to work alongside other incentive 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 SA Power Networks to spend less than its capex forecast declines throughout the period.¹⁵⁷ Because of this SA Power Networks 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, SA Power Networks 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, under the CESS, SA Power Networks' 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, as is the case under our proposed approach for SA Power Networks, then incentives for opex, capex and service are balanced. This encourages SA Power Networks to make efficient decisions on when and what type of expenditure to incur, and to balance expenditure efficiencies with service quality.

SA Power Networks and Origin supported the application of the new CESS.¹⁵⁸

¹⁵⁴ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 5–10.

¹⁵⁵ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 11–12.

¹⁵⁶ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 5–10.

¹⁵⁷ As the end of the regulatory period approaches, the time available for the distributor to retain any savings gets shorter. The earlier a business incurs an underspend in the regulatory period, the greater its reward will be.

¹⁵⁸ SA Power Networks, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 19 February 2014, p. 7; Origin, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 13 February 2014, p. 3.

3.4 Demand management incentive scheme

This section sets out our proposed approach and reasons for applying a demand management incentive scheme (DMIS) to SA Power Networks in the next regulatory control period.¹⁵⁹

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.¹⁶⁰ Demand management that effectively alleviates network utilisation during peak usage periods can be an economically efficient way of deferring the need for network augmentation.

The rules require us to develop and implement mechanisms to incentivise distributors to consider economically efficient alternatives to building more network.¹⁶¹ 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).¹⁶² 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 DMIA¹⁶³ in the previous year, which we then assess and approve under specific criteria.¹⁶⁴
- 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 position is that SA Power Networks will be subject to revenue cap form of control in the next regulatory control period, so Part B is no longer applicable.

3.4.1 AER's proposed approach

Our approach is to continue applying the DMIS to SA Power Networks in the next regulatory control period. We will not apply Part B of the demand management incentive scheme to SA Power Networks in the next regulatory control period because we have decided to apply a revenue cap form of control.

We acknowledge the need to reform the existing demand management incentive arrangements in SA. COAG Energy Ministers are currently considering a series of rule changes¹⁶⁵ proposed by the AEMC

¹⁵⁹ 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.

¹⁶⁰ 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.

¹⁶¹ NER, clause 6.6.3(a).

¹⁶² AER, *Demand management incentive scheme for Qld and SA*, 17 October 2008.

¹⁶³ The DMIA excludes the costs of demand management initiatives approved in our determination for the 2009-14 period.

¹⁶⁴ AER, *Demand management incentive scheme for Qld and SA*, 17 October 2008, p. 5.

in its Power of Choice review¹⁶⁶ 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 may 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 to allow a \$3 million DMIA (\$600 000 each year). The CCP were not in favour of providing a DMIA. They considered the payment and its use by distributors is not subject to sufficient rigour, and in their view, is not in the interests of consumers.¹⁶⁷

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.¹⁶⁸ 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.
- 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 proposed approach

Our approach is to continue applying the DMIA to SA Power Networks in the next regulatory control period. We will not apply Part B of the demand management incentive scheme to SA Power Networks in the next regulatory control period because we have decided to apply a revenue cap form of control.

The reasons for our proposed approach to apply the DMIS to SA Power Networks in the next regulatory control period follows.

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

¹⁶⁵ 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.

¹⁶⁶ AEMC, *Final report, Power of choice review – giving consumers choice in the way they use electricity*, 30 November 2012.

¹⁶⁷ Consumer Challenge Panel discussion with AER staff on 5 March 2014.

¹⁶⁸ NER, clause 6.6.3(b).

customers' willingness to pay for any higher costs resulting from the scheme so benefits to consumers are sufficient to warrant any penalty or reward.¹⁶⁹

We assess projects for which distributor's apply for DMIA funding under a specific set of criteria.¹⁷⁰ 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 studies¹⁷¹ 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.

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.¹⁷² We consider that a revenue cap form of control provides an incentive for SA Power Networks to reduce the quantity of electricity. This is because the 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.¹⁷³ 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.¹⁷⁴ Efficient pricing structures reflect the true

¹⁶⁹ NER, clause 6.6.3(b)(1).

¹⁷⁰ AER, *Demand management incentive scheme for Qld and SA*, 17 October 2008, p. 5.

¹⁷¹ For example, Oakley Greenwood, *Valuing reliability in the national electricity market, final report*, March 2011. This report was prepared for AEMO.

¹⁷² NER, clause 6.6.3(b)(2).

¹⁷³ NER, clause 6.6.3(b)(6).

¹⁷⁴ NER, clause 6.6.3(b)(3).

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.¹⁷⁵ 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.

SA Power Networks submitted that it supports the AER's proposed approach and it will include an appropriate DMIA amount in the regulatory proposal.

3.5 Small-scale incentive scheme

Rule 6.6.4 of the NER states that the AER may, in accordance with the distribution consultation procedures, develop and publish an incentive scheme or schemes (small-scale incentive scheme) that provides DNSPs with incentives to provide standard control services in a manner that contributes to the achievement of the national electricity objective.

These are pilot or test incentive schemes within an environment that limits the sum of money at risk and the length of time of the scheme.

3.5.1 AER's proposed approach

We do not propose to apply a small-scale incentive scheme to SA Power Networks in the subsequent regulatory control period.

3.5.2 Reasons for AER's proposed approach

At this stage, we have not developed any such schemes to encourage more efficient investment or operation of networks, as may be envisaged under this provision of the NER. For this reason, we do not propose to apply a small-scale incentive scheme to SA Power Networks in the subsequent regulatory control period.

¹⁷⁵ NER, clause 6.6.3(b)(4).

SA Power Networks submitted that it is not proposing that such a scheme should be in place at this stage but will notify the AER and include any scheme in the regulatory proposal.¹⁷⁶

¹⁷⁶ SA Power Networks, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 19 February 2014, p. 8.

4 Expenditure forecast assessment guideline

This attachment sets out our intention to apply our expenditure forecast assessment guideline (guideline)¹⁷⁷ including the information requirements to SA Power Networks for the 2015–20 regulatory control period. We propose applying the guideline as it sets out our new expenditure assessment approach developed and consulted upon during the Better Regulation program. The guideline outlines for the distributors and interested stakeholders the types of assessments we will do to determine efficient expenditure allowances, and the information we require from the distributors to do so.

We were required to develop the guideline under the rules.¹⁷⁸ 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. In the F&A we must set out our proposed approach to the application of the guideline.¹⁷⁹

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.¹⁸⁰

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. The guideline itself does not explicitly require these distributors to submit or justify inputs to these models and we may request specific data to assist us with this analysis. 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.

¹⁷⁷ We published this guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864.

¹⁷⁸ NER, clauses 6.4.5, 6A.5.6, 11.53.4 and 11.54.4.

¹⁷⁹ NER, clause 6.8.1(b)(2)(viii).

¹⁸⁰ AER, *Explanatory statement: Expenditure assessment guideline for electricity transmission and distribution*, 29 November 2013.

5 Depreciation

Capital expenditure (capex) refers to expenditure on assets that are long lived. Distributors therefore recover the costs over the life of the asset rather than when the costs are incurred. This return of capital is also called depreciation. The alternative is to compensate distributors for costs entirely in the year they are incurred. This is the approach we use for operating expenses.

The distributors are provided an allowance for depreciation that is calculated on the existing regulatory asset base (RAB) and forecast additions or capex to the RAB. The proportion of depreciation related to forecast capex, like all forecasts, is subject to forecasting error. Once actual capex is known, it is possible to accurately determine what the depreciation allowance would have been. The issue under consideration in this attachment is whether the approach for depreciation in the RAB roll forward should employ the allowance based on forecast capex (forecast depreciation) or actual capex (actual depreciation) over the regulatory control period.

This attachment sets out our proposed approach to use forecast depreciation when rolling forward to establish the RAB at the commencement of the 2020–25 regulatory control period.

Once a distributor's capex allowance is determined, the funding for the approved capex program will be returned to the distributor for each year of the upcoming regulatory control period through the sum of:

- the forecast RAB multiplied by the weighted average cost of capital (WACC);¹⁸¹ and
- depreciation.¹⁸²

As the capex allowance is set before the regulatory control period commences, a distributor has an incentive to spend less than the allowance and through these savings earn higher profits. Hence a distributor can 'keep the difference' between the allowance and what it cost to finance the actual capex until the end of the regulatory control period. Conversely, if a distributor spends more than its allowance, its revenue will not cover the overspend meaning that the distributor has to bear the cost of financing the overspend within the regulatory control period.¹⁸³

The depreciation we use to roll forward the RAB at the end of the current regulatory control period 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.

¹⁸¹ The forecast RAB is the actual RAB at the end of the previous regulatory control period, plus any forecast net capex undertaken in the current regulatory control period, minus any actual depreciation (from assets in place prior to the start of the regulatory control period), minus any forecast depreciation (from net capex undertaken during the regulatory control period).

¹⁸² This is the sum of actual depreciation for assets in place prior to the start of the regulatory control period and forecast depreciation for net capex to be undertaken during the regulatory control period.

¹⁸³ It is these incentives to reduce expenditure that make historical costs a good indicator of future costs where capex is recurrent and predictable. That is, a service provider's efficient costs are 'revealed' over time.

The choice of depreciation approach is one part of the overall capex incentive framework. In particular, the difference between the two approaches is the relative strength of the additional incentive to over-forecast or to underspend capex. This arises during the RAB roll forward at the end of the regulatory control period. To roll forward the RAB, we:

- start with the opening RAB for the regulatory control period
- add actual net capex for each year to the RAB
- remove forecast or actual depreciation for each year from the RAB
- determine the closing RAB at the end of the regulatory control period.

Regardless of the depreciation approach, we always update the RAB to reflect actual (prudent) capex. Therefore, when applying different depreciation approaches in the roll forward process, the closing RAB will only vary due to differences in the depreciation removed from this process.

Under a forecast depreciation approach, a distributor's RAB reduces to reflect the depreciation forecast set at the beginning of the regulatory control period. Whereas under an actual depreciation approach, the distributor's RAB reduces to reflect the re-calculated depreciation amount linked to each year's actual capex. Where actual capex differs from forecast, actual depreciation will be different to the depreciation forecast. Therefore, the two approaches result in different closing RABs at the end of the regulatory control period.

Through the different approaches to depreciation and other building blocks, the regulatory framework creates incentives for distributors to over forecast or to defer efficient expenditure. This can encourage distributors to pursue capex efficiency improvements that will ultimately benefit both the distributor and electricity consumers. The relative sharing ratio between the distributor and consumers will be determined by the year in which the capex overspend or underspend occurs, whether actual or forecast depreciation is used to roll forward the RAB, and the expected life of the asset.

Consumers benefit from improved efficiencies through lower regulated prices. Where a capital expenditure sharing scheme (CESS) is applied, the forecast depreciation approach 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.¹⁸⁴ In summary:

- If there is a capex overspend, actual depreciation will be higher than forecast depreciation. This means that when applying actual depreciation in the roll forward, the RAB will increase by a lesser amount than if forecast depreciation were used. Therefore, 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 when applying actual depreciation in the roll forward, 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.

¹⁸⁴ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 10–12.

The strength of capex reduction incentive from using actual depreciation to roll forward the RAB also varies with the expected 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 proposed approach

Our proposed approach is to use the forecast depreciation approach to establish the RAB at the commencement of the 2020–25 regulatory control period for SA Power Networks. We consider this approach will provide sufficient incentives for SA Power Networks to achieve capex efficiency gains over the 2015–20 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.¹⁸⁵

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.¹⁸⁶ Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective.¹⁸⁷ We must also have regard to:¹⁸⁸

- the incentives the service provider has in relation to undertaking efficient capex, including as a result of the application of any incentive scheme or any other incentives under the rules
- substitution possibilities between assets with relatively short economic lives and assets with relatively long economic lives and the relative benefits of such asset types
- the extent to which capex incurred by the service provider has exceeded forecast capex, and the amount of that excess capex which is not efficient
- the Capital Expenditure Incentive Guideline
- the capital expenditure factors.

5.3 Reasons for AER's proposed approach

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.

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. We apply a sharing factor of 30 per cent to the total efficiency gain/loss under the CESS. This means that the SA Power Networks will bear 30 per cent of any loss and will retain 30 per cent of any gain. The remaining 70 per cent will go to network users.

Consistent with our capex incentive guideline, we have chosen forecast depreciation as our default approach. This is because, in combination with the CESS, it will provide a 30 per cent reward for

¹⁸⁵ NER, clause S6.2.2B(a).

¹⁸⁶ NER, clause 6.4A(b)(3).

¹⁸⁷ NER, clause S6.2.2B(b).

¹⁸⁸ NER, clause S6.2.2B(c).

capex underspends and 30 per cent penalty for capex overspends, which is consistent for all asset classes. We consider this to be a sufficient incentive for SA Power Networks to achieve efficiency gains over the regulatory control period.

We will apply ex post measures for incentivising efficient and prudent capex during a regulatory control period. We will review SA Power Networks' actual capex performance and produce a statement on the efficiency and prudence of all capex that is to be rolled into the RAB (an ex post statement). We may exclude certain types of capex from being included in the roll forward of the RAB. There are three cases in which we may do so including:

- when a distributor has overspent, the amount of capex above the allowance that does not reasonably reflect the capital expenditure criteria can be excluded from the RAB
- where there is an inflated related party margin, the inflated portion of the margin can be excluded from the RAB
- where a change to a distributor's capitalisation policy has led to opex being capitalised, the capitalised opex can be excluded from the RAB.

We consider the incentive provided by the application of the CESS in combination with the use of forecast depreciation and our ex-post capex measure is sufficient to achieve the capex incentive objective.¹⁸⁹

¹⁸⁹ Our ex post capex measures are set out in the capex incentives guideline, AER *capex incentives guideline*, pp. 13–19; the guideline also sets out how all our capex incentive measures are consistent with the capex incentive objective, AER *capex incentives guideline*, pp. 20–21.

6 Jurisdictional matters

6.1 Jurisdictional derogation

We were required to apply the following side constraint to distribution tariffs for small customers for the 2010–2015 regulatory control period:¹⁹⁰

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

However, we are required 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.¹⁹¹

The side constraint to the fixed supply charge for small customers under the jurisdictional derogation is in addition to the 2 per cent tariff basket side constraints under clause 6.18.6 of the rules.¹⁹²

6.1.1 AER's proposed approach

We consider that a national framework for managing issues of tariff volatility should be adopted. On this basis, our proposed approach is to remove the jurisdictional specific side constraint on the fixed supply charge component of the distribution tariff. We acknowledge that price stability through constraints on tariff movements or other consumer protection measures are an important issue for consumers. However, such measures should be considered and applied consistently as part of a national framework.

6.1.2 Reasons for AER's proposed approach

Our proposed approach is to remove the side constraint on the fixed supply charge component of the distribution tariff and adopt the national approach to distribution network pricing arrangements in our price determination for SA Power Networks.

We are proposing to remove the side constraint on the fixed supply charge component because as noted in the preliminary position,¹⁹³ pricing is being considered by the AEMC through changes to the network pricing arrangements arising from the Power of Choice Review.¹⁹⁴ The AEMC is scheduled make a change to the National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 in November 2014.¹⁹⁵ This means that the new national pricing arrangement will be in place for the 2015–20 regulatory control period for SA Power Networks. We acknowledge that price stability through constraints on tariff movements or other consumer protection measures are an important issue for consumers. However, such measures should be considered and applied consistently as part of a national framework. Numerical measures to restrict movements in tariff levels such as side constraints are but one possible option to manage issues of tariff volatility. They are generally blunt instruments that cannot be adapted to specific circumstances. Further, they require

¹⁹⁰ NER, clause 9.29.5(d). This is a jurisdictional derogation in the NER.

¹⁹¹ NER, clause 9.29.5(e).

¹⁹² 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 SA Power Networks 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.

¹⁹³ AER, *Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, December 2014, p. 62.

¹⁹⁴ AEMC, *Power of choice review - giving consumers options in the way they use electricity, Final Report*, 30 November 2012.

¹⁹⁵ AEMC, Power of choice review, <http://www.aemc.gov.au/Major-Pages/Power-of-choice>

careful consideration so that their levels do not hinder movements toward greater efficiency in tariffs. We consider that it is worth exploring, as part of the pricing rule change, the issue of tariff volatility in a holistic way. Other measures might be put in place to better balance the need for greater efficiency in network tariffs and issues central to consumer concerns about tariff volatility. This may include managing expectations as to movements in tariff structures and levels, and information on the design of structures.

While SA Power Networks and Origin¹⁹⁶ supported the removal of the side constraint, other stakeholders expressed concerns in relation to the effectiveness of using the fixed supply charge to achieve more efficient pricing outcomes and the potential impact that increases in the fixed supply charge above the side constraint may have on customers.¹⁹⁷ We acknowledge the merits of these concerns. They emphasise the need to strike a balance between offering efficient and flexible pricing options and providing stability and certainty in network tariffs. We consider these issues should be considered more broadly and addressed consistently under a national framework for distribution network pricing. A national framework is being developed as part of the AEMC's consideration of the distribution network pricing rule change.¹⁹⁸ This framework could introduce a requirement for distributors to consider customer impacts, and consult with stakeholders (consumers and retailers) in the course of designing and introducing tariffs. This might provide for issues around the balance between efficient pricing and price certainty to be managed via a dialogue between distributors and stakeholders, with our oversight in some way. We agree with SACOSS that a distribution tariff structure with greater use of demand and capacity based components, rather than the fixed supply charge component, could better reflect the underlying cost drivers for the network. As noted in our preliminary position, SA Power Networks has commenced a small scale pilot trial of capacity pricing for small customers equipped with interval meters.¹⁹⁹ 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.

6.2 Dual function assets

The F&A must include our determination²⁰⁰ as to whether or not the transmission pricing rules²⁰¹ apply to transmission standard control services provided by any dual function assets owned, controlled or operated by a distributor.²⁰²

If SA Power Networks owns, operates or controls dual function assets it was required to inform us by 30 June 2013. After reviewing the information provided, we were required to make a determination as to whether the transmission pricing rules should apply to transmission standard control services provided by these dual function assets.

A dual function asset is:

¹⁹⁶ SA Power Networks, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 19 February 2014, pp. 8–9.

Origin, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 13 February 2014, pp. 2–3.

¹⁹⁷ CEC, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 13 February 2014, p. 1.

SACOSS, *Submission to AER Preliminary positions paper for Framework and approach for SA Power Networks Regulatory control period commencing 1 July 2015*, 18 February 2014, p. 6.

¹⁹⁸ AEMC, *Power of choice review - giving consumers options in the way they use electricity, Final Report*, 30 November 2012.

¹⁹⁹ SA Power Networks, *Annual Pricing Proposal 2013–2014*, p. 31.

²⁰⁰ NER, clause 6.25(b).

²⁰¹ NER, Part J of chapter 6A.

²⁰² NER, clause 6.8.1(b)(1)(ii).

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 own, operate or control any dual function assets.²⁰³ Therefore, it is not necessary to decide whether transmission pricing rules should be applied for SA Power Networks.

²⁰³ SA Power Networks, Email dated 2 September 2013.

Appendix A – Rule requirements for classification

A.1 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'.²⁰⁴

'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.

A.2 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.²⁰⁵

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.²⁰⁶

²⁰⁴ NER, Chapter 10, definition of a 'distribution service'.

²⁰⁵ NER, clause 6.2.1(c).

²⁰⁶ 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)²⁰⁷
3. the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)²⁰⁸
4. any other relevant factor.²⁰⁹

The rules specify additional requirements for services we have regulated before.²¹⁰ 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.

A.3 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:²¹¹

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.²¹²

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.

²⁰⁷ NER, clause 6.2.1(c)(2).

²⁰⁸ NER, clause 6.2.1(c)(3).

²⁰⁹ NER, clause 6.2.1(c).

²¹⁰ NER, clause 6.2.1(d).

²¹¹ NER, clause 6.2.2(c).

²¹² 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

- b. The provision of:
 - i. meter provision services in respect of meters meeting the requirements of a metering installation types 5 and 6
 - ii. meter installation services in respect of meters meeting the requirements of a metering installation types 5 and 6
 - iii. regular meter read services in respect of meters meeting the requirements of a metering installation types 5 and 6
 - iv. energy data and storage services (excluding those required for standard control services), unscheduled meter reading and metering investigation, directly associated with types 5 and 6 metering services.
- 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, 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. 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 is or is to be installed, or
 - ii. in respect of meters meeting the requirements of a metering installation type 6 and of a metering installation type 5 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

- b. Moving mains, services, meters and other associated assets 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.
- c. 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.
- x. Other lighting services

Appendix C – Summary of submissions

Table C.1 Summary of submissions on the preliminary position F&A

Issue	Stakeholder	Summary	AER response
Classification of services	Origin	Strongly supported the AER continuing to classify metering services for type 6 meters as alternative control services.	We consider it is appropriate to reclassify type 5 meter services from negotiated to alternative control. See section 1.3.3.
		Supported the provision of metering services being broken down into a meter installation service and meter provision service, in the interests of transparent pricing.	
		Supported type 5 meters being reclassified from negotiated to alternative control. Highlights that the SA Government's proposed policy that type 5 meters be installed as new and replacement meters and that this meter can only be provided by distributors.	
	SACOSS	<p>Seek assurance from us that nothing in the F&A will add to or reinforce any barriers to achieving its policy proposals to expand monthly meter reading to vulnerable consumers.</p> <p>The treatment of metering in the F&A must contain sufficient flexibility in order to, at the least, not add to or reinforce any barriers to an efficient workable solution (introduction of smart(er) meters in SA). Stated that 'non-standard type 6 import and export meters is a prima-facie challenge to the idea of 'negotiated services' where there is no contestability.</p>	Non-standard Type 6 import and export meters to be reclassified as alternative control service. See section 1.3.3.
	Vector	Supported our preliminary position to classify type 6 and 5 meters in South Australia (and Qld) as alternative control services.	See section 1.3.3.
	Citelum Australia	<p>Suggested that type 7 unmetered connection points be made contestable or shifted from standard control to alternative control.</p> <p>Supported our continued classification of public lighting services as a Negotiated Distribution Service.</p>	Type 7 unmetered services will remain classified as standard control. See section 1.3.3.
	LGA	Supported our continued classification of public lighting services as a Negotiated Distribution Service.	Public lighting services will continue to be classified as negotiated services. See section 1.3.4.
	DPTI	<p>Supported our continued classification of public lighting services as a Negotiated Distribution Service.</p> <p>Stated that the definition of 'asset</p>	We consider that the current definition of 'asset relocations' would benefit from additional clarity to ensure that the negotiated services framework applies to all

Issue	Stakeholder	Summary	AER response
		relocation services' is unclear. Suggested alternative wording to ensure that SA Power Networks is bound to carry out the services under the negotiated service principles, criteria and the framework for negotiation.	asset relocations. The amended definition is set out in appendix B.13.
	TTEG	Supported our continued classification of public lighting services as a Negotiated Distribution Service.	
	CCP	Supported our preliminary position to classify type 5 and 6 metering services as alternative control and public lighting services as negotiated.	
	SA Power Networks	<p>Type 6 metering services</p> <p>Supported costs directly attributed to reading meters and collecting data being classified as alternative control. However, other systems and capabilities would still be required by SA Power Networks even if it is no longer undertook any meter provision services and these should be classified as standard control.</p> <p>Considered that many of the metering service costs associated with 'non-standard import export meters' are currently not solely allocated to negotiated services. Costs are recovered through a combination of up-front charges (meter installation allocated to negotiated services) and on-going metering tariffs (asset costs, reading and maintenance allocated to alternative control).</p> <p>Would be appropriate to clarify the definition of alternative control type 6 metering services to make clear that they include the standard component of import/export metering services.</p> <p>SA Power Networks considered that the introduction of a new meter transfer fee on small customers may be seen as a significant barrier to meter churn and hinder the SA Governments metering policy.</p> <p>SA Power Networks suggested the following options to address the issue.</p> <p>AER provide an explicit cost allowance for small customer type 6 meter churn allocated to alternative control with costs recovered under meter tariffs paid by SA Power Networks' remaining meter customers, or allocated to standard control and recovered from all customers through DUOS.</p> <p>Classify all existing type 6 meters as</p>	<p>We agree that only costs solely related to the provision of type 6 meter data services should be allocated to alternative control service. Other costs required by SA Power Networks to provide network services can be allocated to standard control services.</p> <p>Our proposed approach only deals with the classification of type 6 meters, it does not provide for the manner in which the allocation of costs for transferring from a type 6 meter is recovered from customers. This will be considered in the price determination process. See Section 1.3.3.</p>

Issue	Stakeholder	Summary	AER response
		<p>standard control and accelerate their depreciation</p> <p>Classify all standard meter provision as standard control</p>	
		<p>Type 5 metering services</p> <p>Considered that type 5 meters should be reclassified from negotiated to alternative control due to the SA Governments policy for new and replacement meters.</p>	<p>We consider it is appropriate to reclassify type 5 meter services from negotiated to alternative control. See section 1.3.3.</p>
		<p>Public lighting</p> <p>Considered that existing public lighting services be reclassified to alternative control and new public lighting services remain as negotiated services.</p>	<p>We propose to retain the current classification for public lighting as a negotiated service. See section 1.3.3.</p>
Control mechanism	Origin	<p>Supported a weighted average price cap (WAPC) but acknowledges that the WAPC has not led DNSP's to price efficiently.</p> <p>Supported a hybrid revenue cap for standard control services.</p>	<p>Our decision is to apply a revenue cap for standard control services. See section 2.3.</p>
	SACOSS	<p>Recognised the rationale for pursuing more cost reflective pricing and the importance of a revenue cap in achieving this. However, the change to a revenue cap must also be seen as significantly de-risking the role of SA Power Networks because customers are taking on the volume risk.</p> <p>Would only support such a change on the basis that this reallocation of risk is adequately reflected in the WACC set by the AER for the upcoming regulatory period.</p>	<p>Our decision is to apply a revenue cap for standard control services. See section 2.3.</p>
	CCP	<p>Supported our preliminary position to apply a revenue cap to SA Power Networks in the next regulatory period.</p>	
	SA Power Networks	<p>Supported a revenue cap for standard control services.</p> <p>Does not support a price cap for alternative control services. Suggests that a revenue cap or to a lesser extent a WAPC should be considered for alternative control services.</p>	<p>Our decision is to apply a revenue cap for standard control services and a price cap for alternative control services. See section 2.3.</p>
Incentive schemes	Origin	<p>Supported the application of the STPIS in the interest of improving service outcomes and value for money.</p>	<p>We will apply the STPIS to SA Power Networks. See section 3.1.3.</p>
	SA Power Networks	<p>Supported the alignment to the national scheme and increase revenue at risk from ±3 per cent to ±5 per cent.</p> <p>Stated that under the current STPIS the</p>	<p>We will consider the application of a transition arrangement to address this issue in the distribution determination process. See section</p>

Issue	Stakeholder	Summary	AER response
		major event days is approximately 5 days per year and under the national scheme the number is approximately 2.5 days per year. Considers that this will create transitional issues when recalculating targets for 2015-2020 and 2020-2025 because the targets are based on five years actual performance	3.1.3.
Fixed supply charge side constraint	Origin	Strongly supported us no longer applying the \$10 cap on increases in fixed charges. Considered that the limit appears arbitrary in terms of its quantum and the \$10 limit is likely to constrain networks moving towards more efficient pricing structures and addressing cross subsidies.	See section 6.1.2.
	SACOSS	Considered that the derogation should remain in its current form until a compelling case is made for its removal. At this stage there is no evidence that the constraint has interfered with past pricing proposals or is likely to do so in the near future. Further, it is highly unlikely that such a constraint will have any long term impact on the pursuit of efficient prices.	We consider that a national framework for managing issues of tariff volatility should be adopted. Our proposed approach is to remove the side constraint on the fixed supply charge component of the distribution tariff. See section 6.1.2 (pp. 75–76).
	CEC	Does not support our preliminary position to remove the side constraint	See section 6.1.2.
	CCP	Considered that the side constraint should be retained.	We consider that a national framework for managing issues of tariff volatility should be adopted. Our proposed approach is to remove the side constraint on the fixed supply charge component of the distribution tariff. See section 6.1.2.
	SA Power Networks	Considered that jurisdictional arrangements that may inhibit more efficient pricing should be removed.	See section 6.1.2.