Preliminary framework and approach

Ausgrid, Endeavour Energy and Essential Energy
Regulatory control period commencing 1 July 2019

March 2017

AUSTRALIAN ENERGY REGULATOR

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Contents

Shortened forms

Shortened Form	Extended Form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CESS	capital expenditure sharing scheme
COAG	Council of Australian Governments
CPI	consumer price index
CPI-X	consumer price index minus X
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
expenditure assessment guideline	expenditure forecast assessment guideline for electricity distribution
GSL	guaranteed service level
F&A	Framework and approach
kWh	kilowatt hours
NEM	National Electricity Market
NEO	National Electricity Objective
NER or the rules	National Electricity Rules
next regulatory control period	1 July 2019 to 30 June 2024
NUoS	network use of system
opex	operating expenditure

Shortened Form	Extended Form
RAB	regulatory asset base
ROLR	retailer of last resort
STPIS	service target performance incentive scheme

Request for submissions

Interested parties are invited to make written submissions to the Australian Energy Regulator (AER) regarding this paper by the close of business, 21 April 2017.

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

Alternatively, submissions can be mailed to:

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

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

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

Enquiries about this paper, or about lodging submissions, should be directed to our Networks Branch on (03) 9290 1444.

Overview

The Australian Energy Regulator (AER) is the economic regulator for transmission and distribution electricity and gas network businesses across Australia (excluding Western Australia). Our powers and functions for the electricity sector are set out in the National Electricity Law (NEL) and National Electricity Rules (NER).

Ausgrid, Endeavour Energy and Essential Energy operate monopoly electricity distribution networks in New South Wales (NSW). The networks comprise the poles, wires and transformers used for transporting electricity across urban and rural population centres to homes and businesses. The three NSW network businesses design, construct, operate and maintain the distribution networks for NSW electricity consumers.

We make regulatory decisions on the revenues the NSW network businesses can recover from their customers. We determine their revenue by an assessment of their efficient costs and forecasts. Our assessment is based on regulatory proposals submitted by the network businesses in advance of a regulatory control period, in this case beginning 1 July 2019. Regulatory proposals set out the network businesses' views on their expected costs, services, incentive schemes and required revenues. Our regulatory determinations set out our decisions on these issues.

The regulatory framework we administer is based on an incentive regime. We set a network business' allowed revenue for a period (typically five years) based on the best available information, rigorous assessment and consideration of consumers' views. Network businesses are then provided with incentives to outperform the revenue we determine. A network business retains any savings for a period time before those savings are passed to customers through lower network bills.

The Framework and Approach (F&A) is the first step in a two year process to determine efficient prices for electricity distribution services in NSW. The F&A determines, amongst other things, which services we will regulate and the broad nature of the regulatory arrangements. This includes an assessment of services (service classification) and whether we need to directly control the prices and/or revenues set for those services The F&A also facilitates early consultation with consumers and other stakeholders and assists electricity distribution businesses prepare regulatory proposals.

Five years ago we published an F&A for the NSW distributers for the current regulatory control period. For the 2019–24 regulatory control period we consider it prudent to review the current NSW F&A paper. Changes to the NER in November 2012 introduced new incentive schemes and allow us to adopt improved approaches to assessing expenditure forecast by the network service providers.[1] The Power of Choice reforms also introduced changes to

[1] Which we outline in our published guidelines. These guidelines are available at www.aer.gov.au/Better-regulation-reform-program.

metering contestability.[2] Further, we are currently developing a new demand management incentive scheme (DMIS)[3] and have recently published a national ring-fencing guideline.[4]

Following release of this Preliminary F&A we will consult with interested parties before issuing our final F&A by 31 July 2017. Table 1 summarises our NSW distribution determination process.

Table 1 New South Wales distribution determination process

Step	Date
AER publishes preliminary positions F&A for NSW distributors	March 2017
AER to publish final F&A for NSW distributors	July 2017
NSW distributors submit regulatory proposals to AER	January 2018
AER publishes Issues paper and holds public forum	Feb/March 2018*
Submissions on regulatory proposal close	May 2018
AER to publish draft decisions	September 2018
NSW distributors to submit revised regulatory proposals to AER	December 2018
Submissions on revised regulatory proposals and draft decisions close	January 2019*
AER to publish distribution determinations for regulatory control period	April 2019

* The date provided is based on the AER receiving compliant proposals. The date may be altered if we receive non-compliant proposals.

Source: NER, chapter 6.

This overview sets out our preliminary positions on:

- classification of distribution services (which services we will regulate)
- control mechanisms (how we will determine prices for regulated services)
- incentives schemes for service quality, capital expenditure and operating expenditure
- expenditure forecasting tools to test the network businesses' regulatory proposals
- how we will calculate depreciation of the network businesses' regulatory asset bases

2 See: http://www.aemc.gov.au/Major-Pages/Power-of-choice.

3 See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism.

4 AER, *Ring-fencing guideline electricity distribution*, November 2016. See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-2016.

- how we will price transmission assets (dual function assets).

Our approach to some of the above matters could be impacted by the outcome of reviews into previous determinations which are currently before the Federal Court. The timing of the results of those reviews is uncertain.

We summarise below our intended approach to each of the above matters. Further details of our approach to each matter are set out in the following chapters.

Classification of distribution services

We regulate distribution services provided by the NSW distributors. Service classification determines the nature of economic regulation, if any, applicable to distribution services. Where there is considerable scope to take advantage of market power, our regulation is more prescriptive. Less prescriptive regulation is required where prospect of competition exists. In some situations we may remove regulation altogether—unregulated distribution services must be provided through a separate affiliate to the distributor following the introduction of our Ring-Fencing Guideline.[5] In broad terms, this means that while existing regulated distribution services will continue to be provided by the distributor, all unregulated distribution services or new services that come into existence within a regulatory control period must be provided outside of the regulated network business, unless it applies for, and receives, a waiver under the ring-fencing guideline.

Table 12 provides an overview of the different classes of distribution services for the purposes of economic regulation under the NER.

Table 2 Classifications of distribution services

Classification		Description	Regulatory treatment
Direct control service	Standard control service	Services that are central to electricity supply and therefore relied on by most (if not all) customers such as building and maintaining the shared distribution network. Most distribution services are classified as standard control.	We regulate these services by determining prices or an overall cap on the amount of revenue that may be earned for all standard control services. The costs associated with these services are shared by all customers via their regular electricity bill.
	Alternative control service	Customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by the local distributor.	We set service specific prices to enable the distributor to recover the full cost of each service from customers using that service.

5 AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

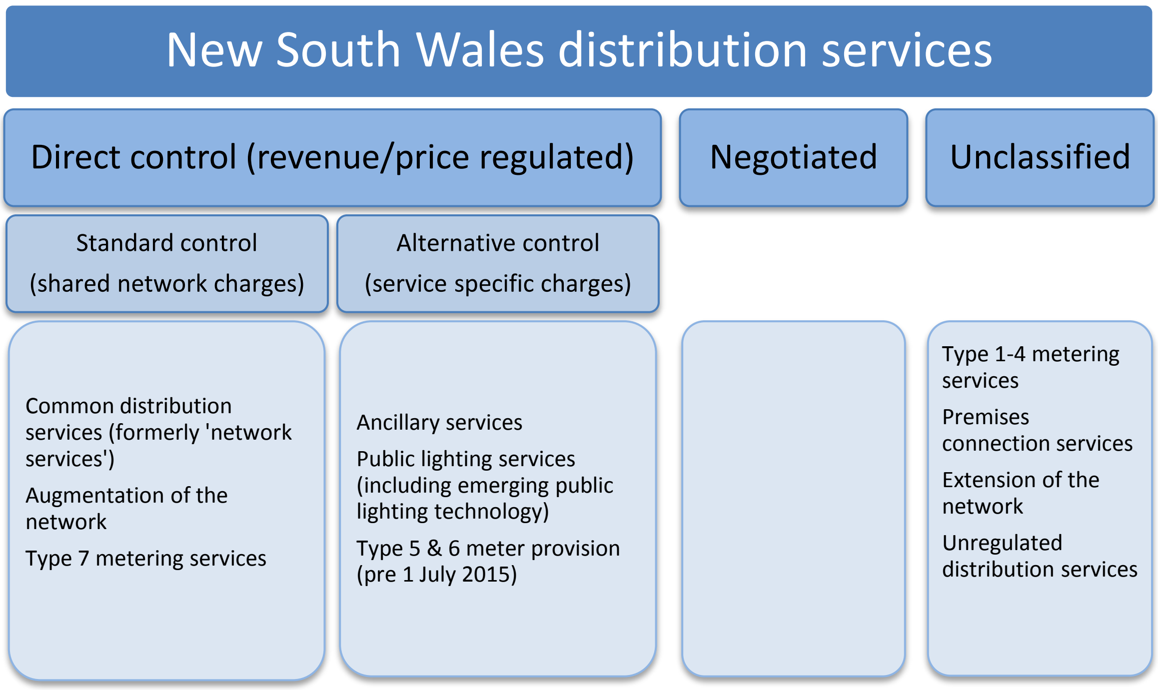
Negotiated service	Services we consider require a less prescriptive regulatory approach because all relevant parties have sufficient countervailing market power to negotiate the provision of those services.	Distributors and customers are able to negotiate prices according to a framework established by the NER. We are available to arbitrate if necessary.
Unclassified service	Services that are not distribution services[6] or services that are contestable.	We have no role in regulating these services.

Source: AER

Our preliminary position is to change the classification of some NSW distribution services for the 2019−24 regulatory control period. While we propose to retain the existing service classifications for most services, we intend to clarify service descriptions to better align with the services being provided, create consistency across jurisdictions as far as practicable and predictability in how new distribution services might be classified.

Our proposed service classifications for the NSW network businesses are set out in figure 1 below.

Figure 1 AER proposed classification of NSW distribution services



Source: AER

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

Our final F&A decision on service classification is not binding for our determination on the NSW network businesses' regulatory proposals. However, under the NER we may only change our classification approach if unforeseen circumstances arise, justifying a departure from our final F&A position.

Control mechanisms

Following on from service classifications, our determinations impose controls on direct control service prices and/or their revenues.[7] We may only accept or approve control mechanisms in a distributor's regulatory proposal if they are consistent with our final F&A.[8] In deciding control mechanism forms, we must select one or more from those listed in the NER.[9] These include price schedules, caps on the prices of individual services, weighted average price caps, revenue caps, average revenue caps and hybrid control mechanisms.

Our preliminary position on the form of control mechanisms for the NSW network businesses are:

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

For standard control services the NER mandate the basis of the control mechanism must be the prospective CPI–X form or some incentive-based variant.[10]

Our final F&A decision on the form of control is binding. We may only vary our decision on control mechanisms in response to unforeseen circumstances.

Incentive schemes

Incentive schemes encourage network businesses to manage their networks in a safe, reliable manner that serves the long term interests of consumers. They provide network businesses with incentives to only incur efficient costs and to meet or exceed service quality targets. Our preliminary position is to apply each of the available incentive schemes to each of the NSW network businesses:

- Service Target Performance Incentive Scheme (STPIS)
- Efficiency Benefit Sharing Scheme (EBSS)
- Capital Expenditure Sharing Scheme (CESS)
- Demand Management Incentive Scheme (DMIS)

7 NER, cl.6.2.5(a).
8 NER, cl. 6.12.3(c).
9 NER, cl.6.2.5(b).
10 NER, cl. 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.

Our final F&A approach on the application of incentive schemes is not binding on us or the NSW network businesses.

Application of our Expenditure Forecast Assessment Guideline

Our Expenditure Forecast Assessment Guideline[11] is based on a reporting framework allowing us to compare the relative efficiencies of distributors. Our preliminary position is to apply the guideline, including its information requirements, to the NSW network businesses in the upcoming regulatory control period.

Our expenditure assessment guideline outlines a suite of assessment/analytical tools and techniques to assist our review of the NSW distributors' regulatory proposals. We intend to apply the assessment/analytical tools set out in the guideline and any other appropriate tools for assessing expenditure forecasts.

Our final F&A approach on the application of our guideline is not binding.

Depreciation

When we roll forward the NSW network businesses' regulatory asset bases (RABs) for the upcoming regulatory control period we must adjust for depreciation. Our preliminary position is to use depreciation based on forecast capex (or forecast depreciation) to establish the opening RABs as at 1 July 2024. In combination with our proposed application of the CESS this approach will maintain incentives for the distributors to pursue capex efficiencies. These improved efficiencies will benefit consumers through lower regulated prices.

Our final F&A position on the depreciation approach is not binding.

Dual function assets

Dual function assets are high-voltage transmission assets forming part of a distribution network. We decide whether to price dual function assets according to transmission or distribution pricing rules.

Under transmission pricing rules the asset costs are recovered from all NSW electricity customers, like the cost of other transmission assets. Distribution pricing rules recover costs from only the customers of a specific distribution network.

Ausgrid and Endeavour Energy operate dual function assets. Essential Energy does not. Our preliminary position is to apply transmission pricing rules to Ausgrid's dual function assets because doing otherwise would significantly impact Ausgrid's customers. We propose to apply distribution pricing rules to Endeavour Energy's dual function assets because, due to the nature of those assets, applying transmission pricing rules would not change their cost recovery—Endeavour Energy customers would still finance those assets.

Our final F&A decision on dual function assets is binding.

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11 AER, *Expenditure Forecast Assessment Guideline for Distribution*, November 2013.

1 Classification of distribution services

This chapter sets out our preliminary position on the classification of distribution services provided by NSW distributors in the 2019−24 regulatory control period. Service classification determines the nature of economic regulation, if any, applicable to distribution services. Applying the classification process prescribed in the NER, we may classify services so that we:

- directly control prices of some distribution services[12]
- allow parties to negotiate services and prices and only arbitrate disputes if necessary, or
- do not regulate some distribution services at all.

Our classification decisions therefore determine which services we will regulate and how distributors will recover the cost of providing those regulated services. We introduced our ring-fencing guideline for electricity distributors and our classification decisions will also settle ring-fencing obligations that will apply to each NSW distributor for the 2019−24 regulatory control period.[13] For these reasons, we have closely reviewed the table of distribution services at appendix B.[14]

We are also aware that the Australian Energy Market Commission (AEMC) is currently assessing rule change proposals from the Council of Australian Governments Energy Council and Australian Energy Council on contestability of energy services.[15] While the AEMC's consideration of these rule change requests is ongoing, we have developed preliminary classification positions within the current regulatory framework. We aim to provide improved clarity, consistency across jurisdictions as far as practicable, predictability in how new distribution services might be classified and service descriptions that better align with the services being provided.[16]

12 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 NER. 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 NER.

13 AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

14 As requested by Endeavour Energy in its letter to the AER: *Request to update F&A paper for the next regulatory control period*, 25 October 2016, p. 3.

15 AEMC, *Consultation paper, National Electricity Amendment (Contestability of energy services) Rule 2016 (COAG), National Electricity Amendment (Contestability of energy services - demand response and network support) Rule 2016 (Australian Energy Council)*, 15 December 2016.

16 As requested by Essential Energy in its letter to the AER *re: Update to framework and approach paper for the 2019−24 regulatory control period*, 25 October 2016, p. 1; Ausgrid's letter to the AER re: *request to replace F&A paper*, 25 October 2016, p. 2.

1.1 AER's preliminary position

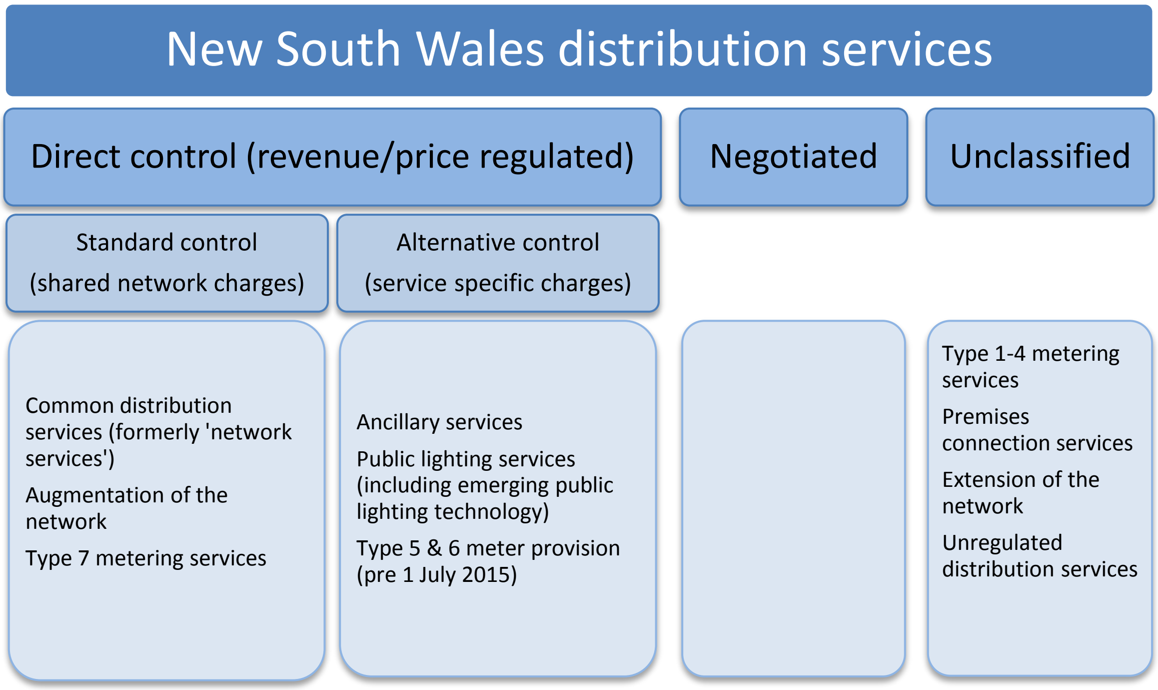
Overall, our preliminary position is to change the classification of some NSW distribution services for the 2019−24 regulatory control period.

Our preliminary position is to group distribution services provided by the NSW distributors as:

- common distribution services (formerly 'network services')
- ancillary services
- metering services
- connection services
- public lighting services
- unregulated distribution services.

Figure 1.1 summarises our preliminary classification of NSW distribution services. Our assessment approach and reasons follow.

Figure 1.1 AER proposed approach to classification of NSW distribution services



Source: AER

1.2 AER's assessment approach

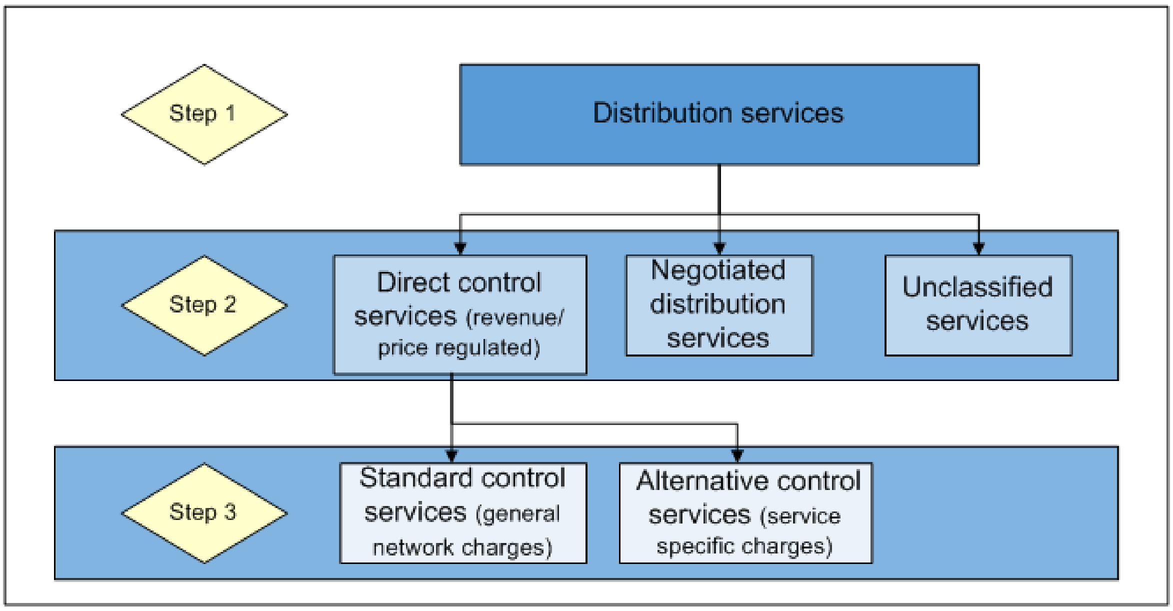
In conducting our assessment of distribution service classification, we commence on the basis that we:

- classify the service, rather than the asset – we can only decide on service classification if we understand what the service being provided is. That is, distribution service classification involves the classification of services distributors supply to customers rather than the classification of:
  - the assets used to provide such services
  - the inputs/delivery methods distributors use to provide such services to
  - customers
  - services that consumers or other parties provide to distributors.
- classify distribution services in groups[17] – our general approach to service classification is to classify services in groupings rather than individually. This obviates the need to classify services one-by-one and instead defines a service cluster, that where a service is similar in nature it would require the same regulatory treatment. As a result, a new service with characteristics that are the same or essentially the same as other services within a group might simply be added to the existing grouping and hence be treated in the same way for ring-fencing purposes. 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, it applies to each service in the group.
- In some circumstances, we may choose to classify a single service because of its particular nature. In addition, a distribution service that does not belong to any existing service classification may be 'not classified' and therefore be treated as an unregulated service. New services (within a regulatory control period) that do not clearly belong to an existing service classification grouping are to be treated as 'not classified'.

Once we group services, the NER sets out a three-step classification process we must follow. We must consider a number of specified factors at each step. Figure 1.2 outlines the classification process under the NER.

17 NER, cl. 6.2.1(b).

Figure 1.2 Distribution service classification process



Source: NER, chapter 6, part B.

As illustrated by figure 2:

- We must first satisfy ourselves that a service is a 'distribution service' (step 1). The NER defines a distribution service as a service provided by means of, or in connection with, a distribution system.[18] 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'.[19]
- We then consider whether economic regulation of the service is necessary (step 2). When 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.
- When we consider that a service should be classified as direct control, we further classify it as either a standard control or alternative control service (step 3).

When deciding whether to classify services as either direct control or negotiated services, or to not classify them, the NER requires us to have regard to the 'form of regulation factors' set out in the NEL.[20] 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 NER also requires us to consider the previous form

18 NER, chapter 10, glossary.
19 NER, chapter 10, glossary.
20 NER, cl. 6.2.1(c); NEL, s. 2F.

of regulation applied to services and the desirability of consistency with the previous approach.[21]

For services we intend to classify as direct control services, the NER requires us to have regard to a further range of factors.[22] These include the potential to develop competition in provision of a service and how our classification may influence that potential; whether the costs of providing the service are attributable to a specific person; and the possible effect of the classification on administrative costs.

The NER also specifies that for a service regulated previously, unless a different classification is clearly more appropriate, we must:[23]

- not depart from a previous classification (if the services have been previously classified), and
- if there has been no previous classification—the classification should be consistent with the previously applicable regulatory approach.[24]

Our classification decisions determine how distributors will recover the cost of providing services.[25] Distributors recover standard control service costs by averaging them across all customers using the shared network. This shared network charge forms the core distribution component of an electricity bill. In contrast, distributors will charge a specific user benefiting from an alternative control service. Alternative control classification is akin to a 'user-pays' system. We set service specific prices to enable the distributor to recover the full cost of each service from the customers using that service. At a high level, a service will be classified as an alternative control service if it is either:

- potentially contestable, or
- it is a monopoly service used by a small number of identifiable customers on a discretionary or infrequent basis and the costs can be directly attributed to those customers.

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

- 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.

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21 NER, cl. 6.2.1(c).

22 NER, cl. 6.2.2(c).

23 NER, cl. 6.2.2(d).

24 NER, cll. 6.2.1(d) and 6.2.2(d).

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

- 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.

In the case of some distribution services, we may determine there is sufficient competition that there is no need for us to classify the service as either a direct control or negotiated service. That is, the market is sufficiently competitive, allowing customers to shop around for the best price. We refer to these distribution services as 'unregulated distribution services'. Broadly, pursuant to our Ring-Fencing Guideline, this means that while existing regulated distribution services will continue to be provided by the distributor, all unregulated distribution services or new services that come into existence within a regulatory control period must be provided outside of the regulated network business, unless it applies for, and receives, a waiver under the ring-fencing guideline.[26]

1.3 Reasons for AER's preliminary position

This section sets out our preliminary service classification and reasons for the NSW distributors' 2019−24 regulatory control period for:

- common distribution services (formerly 'network services')
- ancillary services
- metering services
- connection services
- public lighting services
- unregulated distribution services.

Appendix B contains a detailed table of our preliminary classification of NSW distribution services.

1.3.1 Common distribution services

This service group was formerly called 'network services'. However, to avoid confusion with the defined terms in chapter 10 of the NER, we propose to rename this service group 'common distribution services'. We are open to alternative suggestions for the name of this service group that refers to the services distributors provide over a shared distribution network to all customers connected to it.

Common distribution services are concerned with providing a safe and reliable electricity supply to customers.[27] Common distribution services are intrinsically tied to the network infrastructure and the staff and systems that support the shared use of the distribution network by customers. Customers use or rely on access to common distribution services on

26 AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

27 NER, Chapter 10 glossary.

a regular basis. Providing common distribution services involves a variety of different activities, such as the construction and maintenance of poles and wires used to transport energy across the shared network. The precise nature of activities provided to plan, design, construct and maintain the shared network may change over time. Regardless of what activities make up common distribution services, this service group reflects the provision of access to the shared network to customers.

Our preliminary position is to classify common distribution services as direct control services. Each of the NSW distributors holds an electricity distribution licence which is the only distribution license in place for their respective geographic areas.[28] Under section 17 of the *Electricity Supply Industry Act* (NSW) 1995, a person is prevented from distributing and supplying electricity unless they hold a licence authorising them to do so. These arrangements create a regulatory barrier, preventing third parties from providing common distribution services.[29] Therefore, we consider that there is no opportunity for third parties to enter the market for the provision of common distribution services.

We must further classify direct control services as either standard or alternative control services.[30] Our preliminary position is to retain the current standard control classification for common distribution services. There is no potential to develop competition in the market for common distribution services because of the barriers outlined above.[31] There would be no material effect on administrative costs for us, the NSW distributors, users or potential users by continuing this classification.[32] We currently classify common distribution services (or 'network services') in NSW and all other NEM jurisdictions as standard control services.[33] Further, distributors provide common distribution services through a shared network and therefore cannot directly attribute the costs of these services to individual customers.[34]

Emergency recoverable works

We define emergency recoverable works as the distributor's emergency work to repair damage following a person's act or omission, for which that person is liable (for example, repairs to a power pole following a motor vehicle accident).

Given that these services are provided in connection with a distribution system, we consider this a distribution service. However, we currently do not classify this service, treating it as an unregulated distribution service. This is because the cost of these works may be recovered under common law. That is, the distributor can seek payment of their costs to fix the network from the parties responsible for causing the damage, through the courts if necessary.

28 Licences are issued by Independent Pricing and Regulatory Tribunal of NSW.
29 NER, cl. 6.2.1(c)(1); NEL, ss. 2F(a), (d) and (f).
30 NER, cl. 6.2.2(a).
31 NER, cl. 6.2.2(c)(1).
32 NER, cll. 6.2.2(c)(2), (3).
33 NER, cl. 6.2.2(c)(4).
34 NER, cl. 6.2.2(c)(5).

However, following the introduction of our ring-fencing guideline, classifying this service as an unregulated distribution service would require it to be ring-fenced.

Therefore, our preliminary position is for emergency recoverable works to be subsumed into the common distribution services group and classified as a direct control and standard control service. Distributors are required to perform works to maintain or repair the shared network to ensure a safe and reliable electricity supply. Although we propose classifying this service as a standard control service, a distributor is still expected to seek recovery of the cost of these emergency repairs from the third party where possible. In fact, the distributors are incentivised under the Efficiency Benefit Sharing Scheme to make operating expenditure (opex) savings of this nature.[35] If a distributor is successful in recovering the cost of the emergency repairs from a third party, this payment or revenue, would be netted off the regulatory asset base and treated like a capital contribution. This prevents distributors from recovering the cost of emergency repairs twice—as a standard control charge across the broader customer base and from the responsible third party. Going forward, we propose to adopt this approach across all NEM jurisdictions.

1.3.2 Metering services

All electricity customers have a meter that measures the amount of electricity they use.[36] On 26 November 2015, the AEMC made a final rule that will open up competition in metering services and give consumers more opportunities to access a wider range of metering services.[37]

The competitive framework is designed to promote innovation and lead to investment in advanced meters that deliver services valued by consumers at a price they are willing to pay. Improved access to the services enabled by advanced meters will provide consumers with opportunities to better understand and take control of their electricity consumption and the costs associated with their usage decisions.[38]

The final rule alters who has overall responsibility for the provision of metering services by providing for the role and responsibilities of the Responsible Person to be performed by a new type of Registered Participant − a Metering Coordinator. Any person can become a Metering Coordinator subject to satisfying certain registration requirements.[39]

Retailers are required to appoint the Metering Coordinator for their retail customers, except where a party has appointed its own Metering Coordinator. The final rule also includes a

35 For further information on the operation and application of the AER's Efficiency Benefit Sharing Scheme (EBSS) see: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/expenditure-incentives-guideline

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

37 AEMC, *Competition in metering services information sheet*, 26 November 2015.

38 AEMC, *Competition in metering services information sheet*, 26 November 2015.

39 AEMC, *Competition in metering services information sheet*, 26 November 2015.

number of other features to support the competitive framework for the provision of metering services, including consumer protections.[40]

The new arrangements will commence on 1 December 2017 and have required changes to the NER and the National Electricity Retail Rules (NERR).[41] Consequently, our proposed classification of some metering services will also change for the 2019−24 regulatory control period.

Type 1 to 4 metering services

Large customers use type 1 to 4 meters which provide a range of additional functions compared to other meters. In particular, these meter types have a remote communication ability. Type 1 to 4 meters are competitively available[42] and we do not currently regulate them in NSW or in most other jurisdictions—they are unclassified and our preliminary position is for them to remain so.

Type 5 and 6 metering services

The NSW distributors are currently the monopoly providers of type 5 (interval) and 6 (accumulation) meters. However, from 1 December 2017 (and therefore before the commencement of the next regulatory control period on 1 July 2019), metering services across the National Energy Market will become contestable. Therefore, from 1 December 2017, households and other small customers who traditionally use these meter types may wish to change their metering provider and the type of meter they have. Further, the NSW distributors will no longer be permitted to install or replace existing meters with type 5 or 6 meters. For this reason, type 5 and 6 metering installation and meter provision services become redundant services and are no longer permitted under the NER. Therefore our preliminary position is to not classify these services for the 2019−24 regulatory control period.

However, the NSW distributors may still recover the capital cost of type 5 and 6 metering equipment installed either before or after 1 July 2015 as an alternative control services. Type 5 and 6 metering services were unbundled from standard control services in our final determination for 2015−19 regulatory control period[43] to promote customer choice and remove any classification barriers limiting contestable provision of these meters.[44] This approach aligned with AEMC's Power of Choice recommendations to unbundle metering costs from shared network charges.[45]

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40 AEMC, *Competition in metering services information sheet*, 26 November 2015.

41 AEMC, *Competition in metering services information sheet*, 26 November 2015.

42 NER, cll. 7.2.3(a)(2) and 7.3.1.A(a)).

43 AER, *Final decision Ausgrid/Endeavour Energy/Essential Energy 2015−19 regulatory control period, Attachment 13 Classification of services*, April 2015, pp. 13−11 to 13−15.

44 AER, *Final decision ActewAGL 2015−19 regulatory control period, Attachment 13 Classification of services*, April 2015, pp. 13−11 to 13−15.

45 AEMC, *Consultation paper — National electricity amendment (expanding competition in metering and related services)*, April 2014.

Ancillary services − Metering

The NSW distributors may be required to provide other services to support the metering contestability framework.

Some examples include:

- Type 5 meter final read − to conduct a final read on removed type 5 metering equipment as required by the Australian Energy Market Operator Service Level Procedure.[46]
- Distributor arranged outage for purposes of replacing meter − at the request of a retailer or metering coordinator, provide notification to affected customers and facilitate the disconnection/reconnection of customer metering installations where a retailer planned interruption cannot be conducted.[47]
- Type 5 to 7 non-standard meter data services − the provision of information of the customer's energy consumption or distributor charges following the request from a retailer, a retailer's customer or a retailer customer's authorised agent.[48]

A detailed list of metering services is contained in appendix B.

Our proposed classification and reasons for ancillary services (which captures ancillary metering services) are set out in section 1.3.4 below with our broader discussion on all ancillary services.

Type 7 metering services

Type 7 metering services are unmetered connections with a predictable energy consumption pattern (for example, public lighting connections). Such connections do not include a meter that measures electricity use. Charges associated with type 7 metering services relate to the process of estimating electricity use. For example, the distributor estimates public light usage using the total time the lights were on, the number of lights in operation, and the light bulb wattage. NSW distributors are the monopoly providers of type 7 metering services in NSW.[49]

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46 This Service Level Procedures applies to Metering Providers who are accredited and registered by AEMO to provide metering services within the National Electricity Market (NEM). The Service Level Procedure details the technical requirements and performances associated with the provision, installation and maintenance of a metering installation. This Service Level Procedures is established under clause 7.14.1A of the NER for the various categories of registration and metering installation types as detailed under clause S7.4 of the NER.

47 AEMC, *Rule determination, National Electricity Amendment (Expanding competition in metering and related services) Rule 2015; National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015*, 26 November 2015, p. 206.

48 This wording has been added to reflect AMEO Metering Data Provision Procedures that the NSW distributors will be subject to.

49 NER, cl. 7.2.3(a)(2).

We therefore consider that there is no potential to develop competition in the provision of type 7 metering services.[50] We intend to classify type 7 metering services as direct control services and further, as standard control services. This is a continuation of the current classification of type 7 metering services.[51]

Metering coordinator, metering provider, metering data provider

Under the competitive framework for metering, the roles of metering coordinator, metering provider and metering data provider may be performed by any registered person.[52]

In preliminary discussions some distributors have raised the possibility of creating a transitional metering coordinator, provider and data provider services. This is because each distributor will be appointed as the metering coordinator as at 1 December 2017.[53] Some network service providers suggest that by creating this service and classifying it as an alternative control service, it would obviate the need to ring-fence a transitional service until, for example, alternative metering coordinators are appointed. However, we consider that pre-existing type 5 and 6 metering services already encompasses these roles and is reflected in the alternative control service charges.

While we consider a metering coordinator, metering provider or metering data provider are distribution services, our proposed approach is to not classify these services.[54] That is, we propose to treat them as unregulated distribution services. We appreciate the distributors' view of creating an alternative control service until the market for these services is established. However, contestability in metering means there is significant potential to develop competition for the provision of these services.[55] For example, to create a transitional metering coordinator service and classify it as an alternative control service may cause customers confusion about their ability to source a metering coordinator from the competitive market and set their own commercial arrangements. This would not be in the long term interests of consumers and would not promote the policy goals of the metering contestability framework.[56]

From a ring fencing perspective, the provision of these services will need to be separated from the provision of direct control services. We may consider (subject to an application)

50 NER, 6.2.2(c)(1).

51 AER, *Final decision Ausgrid/Endeavour Energy/Essential Energy, Attachment 13, Classification of services*, April 2015, p. 13−26.

52 AEMC, *Rule determination, National Electricity Amendment (Expanding competition in metering and related services) Rule 2015; National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015*, 26 November 2015, pp. 127−131.

53 AEMC, *Rule determination, National Electricity Amendment (Expanding competition in metering and related services) Rule 2015; National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015*, 26 November 2015, p. 129.

54 NER, chapter 10, glossary; *Ergon Energy Corporation Ltd v Australian Energy Regulator* [2012] FCA 393

55 NER, cl. 6.2.1 (c)(1), NEL, ss. 2F(a), (d), (e), (f), (g) and NER, cl. 6.2.2(c)(1).

56 AEMC, *Rule determination, National Electricity Amendment (Expanding competition in metering and related services) Rule 2015; National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015*, 26 November 2015.

ring-fencing waivers around office and staff sharing obligations where there are no third party competitors (for a time).[57] While this may increase the administrative costs of the distributor in establishing an affiliate to provide these services, we consider the benefits to customers in being about to secure services from a competitive market outweighs this cost.[58]

We appreciate that this is a new issue that is not entirely clear. We therefore welcome stakeholder comments.

1.3.3 Connection services

Put simply, a connection service refers to the services a distributor or accredited service provider (ASP)[59] performs in order to:

- connect a person's home, business or other premises to the electricity distribution network (premises connection)
- get more electricity from the distribution network than is possible at the moment (augmentation);
- extend the network to reach a person's premises (extension).

New South Wales, by virtue of the contestability framework contained in the *Electricity Supply Act* 1995 (NSW), permits customers to choose whether a NSW distributor or an ASP will perform certain connection works where the customer is required to fund the connection in full or in part. The ability of customers to choose who will perform the work and negotiate the price in a competitive market means there are only limited circumstances where we regulate connection services in NSW.

Table 3 lists the definitions of each connection type together with our preliminary classification of each type. Notably, our preliminary position does not differ from the 2014−19 regulatory control period.[60]

Table 3 AER's preliminary classification of connection services in NSW

Connection services - descriptions	Preliminary classification
Premises connections—Includes any additions or upgrades to the connection assets located on the customer's premises which are contestable (Note:	

57 AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

58 NER, cl. 6.2.2(c)(2).

59 The ASP scheme is administered by the NSW Department of Trade and Investment.

60 AER, *Final decision Ausgrid/Endeavour Energy/Essential Energy distribution determination, Attachment 13 − Classification of services*, April 2015; NER, cll. 6.2.1(c)(3) and (d) and 6.2.2(c)(3) and (4).

Connection services - descriptions	Preliminary classification
excludes all metering services).[61]	
Premises connection assets can be further described as: A. Design and construction of premises connection assets (where these services are provided contestably) B. Part design and construction of connection assets that are not available contestably (generally as a result of safety, reliability or security reasons). Those parts of project works that are performed and funded by the distributor.	A. Unclassified B. Standard control
Extensions—An enhancement required to connect a power line or facility outside the present boundaries of the transmission or distribution network owned or operated by a network service provider that is: A. undertaken by an ASP on behalf of a customer B. undertaken by a customer but partly funded by a NSP (NSP contribution would be classified as a standard control service while the customer funded component of the service would be unclassified.) C. undertaken by a network service provider	A. Unclassified B. Unclassified/standard control based on financial contribution C. Standard control
Augmentations— A. Any shared network enlargement/enhancement undertaken by a distributor which is not an extension B. Any shared network enlargement/enhancement undertaken by a customer, but partly funded by a NSP (NSP contribution would be classified as a standard control service while the customer funded component of the service would be unclassified) C. Any shared network enlargement/enhancement undertaken by a customer	A. Standard control B. Unclassified/standard control based on financial contribution. C. Unclassified

Source: AER analysis

We consider each connection type below.[62]

Premises connections

We consider that premises connections refer to any additions or upgrades to the connection assets located on the customers' premises (but excludes all 'metering services').

New South Wales has a working contestability framework and competitive market to provide premises connections under the *Electricity Supply Act* 1995 (NSW). This means customers

61 Also referred to as 'premises connection assets' at cl. 5A.A.1 of the NER.
62 NER, cll. 6.2.1 and 6.2.2.

can choose their own service provider and negotiate a price for premises connections. Where no third party service provider exists, such as in a rural area, the distributor acts as the 'service provider of last resort'. In this instance, the distributor provides the service on a competitive neutral basis.[63] Otherwise, the NSW distributors do not offer premises connections.

For the above reasons, we intend not to classify premises connections in the 2019−24 regulatory control period. We consider that this is appropriate as the service is subject to competition on the open market.[64]

Extensions

Similar to premises connections, NSW has a working contestability framework and competitive market to provide extension services. Customers can choose their own service extension provider. We consider customers' ability to choose balances the economies of scale and scope otherwise available to the NSW distributors.[65] Where no third party service provider exists, such as in some rural areas, the distributor acts as the 'provider of last resort'. This arrangement provides competitive neutrality.[66]

The NSW distributors may reasonably require works to facilitate further connections, however, the costs will be apportioned between the customer seeking the extension and any additional work the distributor elects to undertake. In the event that subsequent customers do connect to the extension, the customer may seek to share its extension cost under a cost sharing scheme (pioneer scheme) operated by the distributor.[67]

For these reasons, only extensions performed by the distributor or where the distributor makes a financial contribution to the extension will be classified as standard control services. In this instance the distributor is extending the shared network to benefit a non-identifiable customer base and the costs will be shared.[68] All other extensions are unregulated distribution services and will not be classified.

Augmentations

Augmentations refer to any shared network enlargement/enhancement undertaken by a distributor, which is not an extension. For example, expansion of the shared network to accommodate increased demand. We acknowledge there may be some circumstances where a customer may be required to contribute to an augmentation in order to connect to the network. Typically, network augmentation is not attributable to a specific customer. However, we do not wish to preclude the possibility of a customer contributing to

63 NEL, s. 2F(a), (d), (f) and (g).
64 NER, cl. 6.2.1(d).
65 NEL, s. 2F(b) and (c).
66 NEL, s. 2F(a), (d), (f) and (g).
67 NER, chapter 5A and AER*, Connection charge guidelines for electricity retail customers, Under chapter 5A of the National Electricity Rules*, June 2012, p. 22.
68 NER, cl. 6.2.2(c)(5).

augmentation at this point. The NSW distributors will be required to identify these circumstances in their Connection Policies that will form part of their regulatory proposals.[69]

The NSW distributors each hold an electricity distribution licence to provide services for their respective distribution areas in NSW. We consider that these NSW licensing arrangements create a regulatory barrier for third parties to perform augmentations.[70] Additionally, the NSW contestability framework which allows ASPs to perform premises connections and extensions competitively, does not apply to augmentation of the shared network. The NSW distributors may engage a third party to perform augmentations. However, we understand that in most instances, the NSW distributors will not permit third parties to perform augmentations because of the potential impact on the safety, security and reliability of the network.

In most cases, if not all, augmentation of the network is a cost shared by all customers. We therefore consider that the NSW distributors possess significant market power in providing augmentations to the shared network. A third party can only perform an augmentation at a distributor's discretion. This creates a monopoly, which requires a stringent regulatory approach. Additionally, we have classified connection services in other NEM jurisdictions as direct control services.[71]

We must further classify direct control services as standard or alternative control services.[72] Our proposed approach is to classify augmentations as standard control services. This is consistent with the current regulatory approach because:

- There is no prospect for competition in the market for augmentations. Our classification will not influence the potential for competition. Rather, the absence of competition is due to the NSW distributors performing augmentations to ensure the safe and reliable supply of electricity to network customers. Additionally, the contestability framework does not extend to augmentations.
- There would be no material effect on administrative costs to us, the NSW distributors, users or potential users. This is because classifying augmentations as standard control services involves the whole customer base sharing the cost.
- We currently regulate augmentations in all other NEM jurisdictions as direct and standard control services.
- The distributors provide augmentations to benefit the shared network and cannot directly attribute costs to individual customers.

For these reasons, we consider that it is clearly more appropriate to retain the current standard control service classification for augmentations.[73]

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69 The NSW distributors are yet to submit their Connection Policies (indeed, they may be some way from being drafted). Consequently, the classifications may be inconsistent with the Connection Policies. We will consider any such adjustments in our final F&A and if necessary, draft determination to avoid any inconsistencies.

70 NEL, s. 2F(a).

71 NER, cll. 6.2.1(c)(2) and (c)(3).

72 NER, cl. 6.2.2(c),

1.3.4 Ancillary services

Ancillary services share the common characteristics of being services provided to individual customers on an 'as needs' basis (e.g. meter testing and reading at a customer's request, moving mains, temporary supply, alteration and relocation of existing public lighting assets). Ancillary services involve work on, or in relation to, parts of the NSW distributors' respective distribution networks. Therefore, similar to common distribution services only the relevant distributor may perform these services in its distribution area.

The above factors create a regulatory barrier preventing any party other than the NSW distributors providing ancillary services in their respective distribution area.[74] Because of this monopoly position, customers have limited negotiating power in determining the price and other terms and conditions on which the distributors provide these services. These factors contribute to the view that the NSW distributors possess significant market power in providing ancillary services.[75]

For these reasons, we consider that we should classify ancillary services as direct control services.

Further, we intend to classify ancillary services as alternative control services because the NSW distributors provide these services to specific customers.[76] As such, the full cost of each ancillary service is directly attributable to an individual customer.[77] This results in costs that are more transparent for customers.

We adopt this view even though ancillary services do not exhibit signs of competition or potential for competition. We also note that there would be no material effect on the administrative costs to us, the distributors, users or potential users of the network.[78] This is because classifying ancillary services as alternative control services is consistent with the current approach.

To the extent that the provision of ancillary services become or may become contestable through future changes to the regulatory or contestability frameworks, our proposed alternative control classification would allow distributors to compete as a discrete price for the service is set for each ancillary service.

1.3.5 Public lighting

The NSW distributors operate and maintain the majority of public lighting systems throughout NSW. The distributors provide these services on behalf of local councils and government departments responsible for public lighting in NSW.

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73 NER, cl. 6.2.2(d).
74 NEL, s. 2F(a).
75 NEL, s. 2F.
76 NER, cl. 6.2.2(c)(5).
77 NER, cl. 6.2.2(c)(5) - this includes a small number of identifiable customers.
NER, cl. 6.2.2(c)(2).

The NER does not define public lighting services. However, we have consistently defined public lighting services in other distribution determinations as:

- the operation, maintenance, repair and replacement of public lighting assets
- the alteration and relocation of public lighting assets, and
- the provision of new public lighting.[79]

We also propose to continue to include emerging public lighting technology as part of the public lighting services group. Emerging public lighting technology relates to luminaires that the NSW distributors do not provide at the time of our distribution determination. However, emerging public lighting technology may become available during the 2019−24 regulatory control period. We note Endeavour Energy's request that we consider classifying emerging public lighting technologies as negotiated distribution services.[80]However, we intend to classify public lighting (including emerging public lighting technology) as a direct control service and further, as an alternative control services. Our reasons follow.

During the 2014−19 NSW distribution determination process we received numerous submissions[81] requesting that all public lighting services remain alternative control services. It was clear from a number of submissions that many NSW public lighting customers thought the distributors did not devote sufficient time to their public lighting interests.[82] We were concerned that the NSW distributors lacked commercial incentives to engage meaningfully with their public lighting customers. That is, public lighting forms a small part of the distributors' revenue. At this time we have received no evidence to the contrary to prompt us to revisit the classification of NSW public lighting services. We would be pleased to receive updates from interested stakeholders on this issue.

Until contrary evidence comes to hand, we consider a direct form of regulation is necessary. We consider there to be significant barriers preventing third parties from providing public lighting services. While the NSW distributors do not have a legislative monopoly over these services, a monopoly position exists. This is because the NSW distributors own the majority of public lighting assets. That is, other parties would need access to poles and easements for instance to hang their own public lighting assets.[83] However, the NSW distributors own and control such supporting infrastructure. Therefore, similar to common distribution

79 AER, *Final framework and approach for Queensland*, April 2014, p. 66; AER, *Final framework and approach for Victoria*, October 2014, p. 62.

80 As requested by Endeavour Energy in its letter to the AER: *Request to update F&A paper for the next regulatory control period*, 25 October 2016, p. 3.

81 NSW DNSPs, *Response to the AER's preliminary framework and approach paper*, 17 August 2012, pp. 3; REROC, *Submission on the AER framework and approach paper*, August 2012, p. 5; Gosford City Council, *Submission on the AER framework and approach paper*, 23 August 2012, p. 1; SSROC, *Submission on the AER framework and approach paper*, 24 August 2012, p. 1; Bankstown City Council, *Submission on the AER framework and approach paper*, 28 August 2012, p 1.

82 For example, *Bankstown City Council, Submission on the AER's preliminary positions F&A paper*, 28 August 2012, p. 2; SSROC, *Submission on the AER's preliminary positions F&A paper*, 24 August 2012, p. 5; REROC, *Submission on the AER's preliminary positions F&A paper*, August 2012, p. 5.

83 NER, cl. 6.2.1(c)(1), NEL, s. 2F(a), (d).

services, ownership of network assets restricts the operation, maintenance, alteration or relocation of public lighting services to the NSW distributors. There is some limited scope for other parties to provide some public lighting services. For example, other parties may construct new public lights or perform works on independently owned public lighting assets.[84] Apart from these limited exceptions, we consider that a high barrier prevents third parties from entering this market. This limits competition in public lighting and results in the NSW distributors possessing significant market power.[85]

We understand that the NSW Public Lighting Code provides some guidance on the relationship between NSW distributors and customers, however the code is non-binding.[86] For these reasons, we consider that customers do not have adequate countervailing market power.[87]

We currently regulate public lighting services in all NEM jurisdictions except the Australian Capital Territory and Northern Territory (where public lighting is government owned). We have classified some public lighting services in South Australia and Victoria as negotiated distribution services. However, the NER does not require us to classify similar services consistently between NEM jurisdictions.[88] Unless new information comes to hand, we are not satisfied that the NSW distributors or their customers are adequately equipped to negotiate the provision of public lighting services.

As direct control services, we must further classify public lighting services as either standard or alternative control services.[89] We intend to classify public lighting services as alternative control services for the following reasons:

- classifying public lighting services as alternative control services provides scope for third parties and new entrants to provide public lighting services for new public lighting assets.[90]
- classifying public lighting services as alternative control services may encourage other potential service providers to enter the market in the future— if the NSW Government implements a contestability regime. In the meantime, an alternative control classification supports the National Electricity Objective by ensuring distributors provide safe and reliable public lighting services to the community.[91]

84 That is, assets, like poles, not owned by the NSW distributors. NEL, s. 2F(f).

85 NEL, s. 2F(d).

86 Department of Energy, Utilities and Sustainability, *NSW public lighting code*, 1 January 2006. The NSW Department of Industry and Investment issued a discussion paper in December 2009 titled *'NSW Public Lighting Code Review'*. This department also published *'NSW Public Lighting Code 2011, Explanatory Paper'* in early 2011, stating that a final Code would be presented to the Minister in April 2011 (p. i). It does not appear that a final Code has been released.

87 NEL, s. 2F (d).

88 NER, cll. 6.2.1(c)(3) and 6.2.2(c)(3) and (4).

89 NER, cl. 6.2.2(c).

90 NER, cl. 6.2.2(c)(1).

91 NER, cl. 6.2.2(c)(1).

- there would be no material effect on administrative costs to the AER, NSW distributors, users or potential users. This is because we are retaining the current classification.[92]
- the NSW distributors can directly attribute the costs of providing public lighting services to a specific set of customers. This includes local councils and other government agencies.[93]

For these reasons, we consider that there is insufficient basis to move away from the presumption that public lighting services in NSW should be alternative control services.[94]

1.3.6 Unregulated distribution services

Unregulated distribution services is the term we us to describe distribution services which we have not classified as either direct control or negotiated services.[95] These services are provided on an unregulated basis and are potentially provided by other service providers in a competitive market. This group of services is particularly important as the number and types of services offered by distributors is growing and changing.

In November 2016, we released the Ring-Fencing Guideline for Electricity Distribution.[96] Our ring-fencing guideline interacts with a number of regulatory instruments, including our service classification decisions. Specifically, our service classification decisions set ring-fencing obligations for each distributor for its next regulatory control period.[97] Under our ring-fencing guideline, any unregulated distribution service would be protected by functional and accounting separation. This removes the potential risk of a distributor benefitting from its privileged access to network information to gain a competitive advantage.

Figure 1.3 illustrates the interrelationship between service classification and ring-fencing obligations. Essentially, a distributor may only provide distribution services. Affiliated entities may provide other electricity services. For the purposes of this preliminary F&A we are not addressing interactions with other regulatory frameworks in detail as these are set out in the explanatory statement to the ring-fencing guideline.[98]

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92 NER, cl. 6.2.2(c)(2).

93 NER, cl. 6.2.2(c)(5).

94 NER, cl. 6.2.2(c)(3).

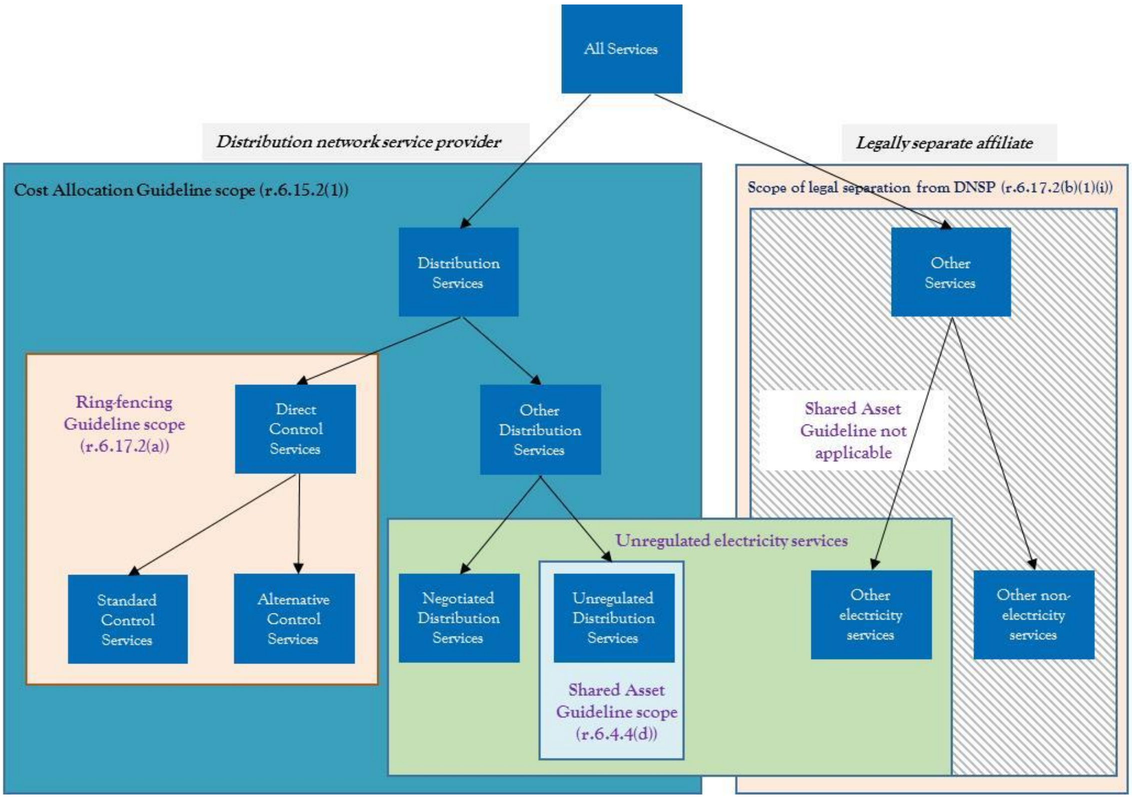
95 AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, p. 13.

96 AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

97 AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, pp. 13−16.

98 AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, pp. 13−16.

Figure 1.3 Distribution services linkage to ring-fencing



Source: AER

In approaching classification of unregulated distribution services, distributors (and the AER) will need to consider if the service would be better offered by an affiliate and therefore not classified (i.e. fall into the 'other electricity services' group on the services diagram above).

Alternatively, some of these distribution services could be classified as alternative control services. As part of our distribution determination, we would set a cost-reflective price for the service based on information provided by the distributor. Customer uptake of the distributor provided service would depend on whether the price of the service is competitive with that of other market participants. It should be noted that if a service is classified as an alternative control service, it would not be subject to ring-fencing obligations, such as the requirements to use a different brand, to use separate offices and to not share staff. Consequently, there are market effects of classifying a potentially contestable service as an alternative control service rather than an unregulated service.

Developing a comprehensive list of unregulated distribution services will be challenging as this service group will capture all distribution services that are contestable services. This includes all contestable metering and contestable connection services.

Distributors, when considering what unregulated distribution services they offer, should refer to the examples contained in the explanatory statement to the ring-fencing guideline[99] and their unregulated revenue streams. For example, a distributor may earn additional revenue from say NBN Co. by permitting NBN Co. to hang its wires from the same poles. The service is 'providing access to electricity poles'. Similarly, some other access to a network asset that forms part of the regulatory asset base (RAB) may be rented to a third party. The service for classification is 'access to a RAB asset'.

We expect that there will be a number of distribution services that distributors may propose to provide on a ring-fenced basis that are currently unregulated services.

99 AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, Appendices A and B, pp. 77−86.

2 Control mechanisms

Our distribution determination must impose controls over the prices (and/or revenues) of direct control services.[100] This section sets out our preliminary positions, together with our reasons, on the control mechanisms to apply to NSW distributors' direct control services for the 2019–24 regulatory control period. This section also sets out our preliminary positions on the formulae to give effect to these control mechanisms.

As discussed in chapter 1, 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. Appendix B provides our preliminary position classification of the NSW distributors' distribution services.

The form of control mechanisms in a distributor’s regulatory proposal must be as set out in the relevant F&A paper.[101] Additionally, the formulae that give effect to the control mechanisms in a distributor's regulatory proposal must be the same as the formulae set out in the relevant F&A paper. The formulae cannot be altered unless we consider that unforeseen circumstances justify departing from the formulae set out in that paper.[102]

This preliminary F&A paper does not address the form of control mechanism for Ausgrid's dual function assets which will be treated as prescribed transmission services.[103] The NER requires prescribed transmission service revenues to be subject to a revenue cap form of control.[104] The revenue cap formula for these services will be determined as part of our distribution determination. Our preliminary positions on dual function assets are discussed in chapter 6.

2.1 AER's preliminary position

Our preliminary position is to apply the following forms of control in the 2019–29 regulatory control period:

- Revenue cap — for services we classify as standard control services.
- Caps on the prices of individual services — for services we classify as alternative control services.

For standard control services, we note all the NSW distributors' proposed the continuation of a revenue cap control mechanism over the 2019–24 regulatory control period.[105] However,

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100 NER, cl. 6.2.5(a).
101 NER, cl. 6.12.3(c).
102 NER, cl. 6.12.3(c1).
103 NER, cll. 6.25(c)(ii), NER, cl. 6A.10.1A(b).
104 NER, cl. 6A.3.1.
105 Ausgrid, *Ausgrid’s letter regarding framework and approach paper and dual function assets for 2019-24 determination*, 25 October 2016, p. 2; Endeavour Energy, *Request to AER to update the framework and approach for the next regulatory control period*, 25 October 2016, attachment A, pp. 1–2; and Essential Energy, *Essential Energy’s framework and*

the NSW distributors' proposed some amendments to the revenue cap formulae to align the formulae with more recent AER decisions. We consider our preliminary positions formula as set out in figure 2.1 adequately addresses the NSW distributors' considerations.

For alternative control services, we note the NSW distributors' proposed the continuation of the price caps over the 2019–24 regulatory control period.[106] However, Ausgrid proposed an amendment to the current price cap formulae to include an adjustment factor for recovery of any approved pass through amounts.[107] We have accepted this proposal as it is consistent with the prescribed pass through event definitions set out in the NER which reference direct control services.[108]

2.2 AER's assessment approach

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

- the form of the control mechanisms[109]
- the formulae to give effect to the control mechanisms
- the basis of the control mechanism.[110]

The NER sets out the form of control mechanisms that may apply to both standard and alternative control services:[111]

- 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 factor and applicable adjustment factors. A distributor complies 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 services (price caps)[112]

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)

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approach submission, 25 October 2016, p. 1.

106 Ausgrid, *Request to replace Framework and Approach paper*, October 2016, p. 5; Endeavour Energy, *Request to AER to update the framework and approach for the next regulatory control period*, 25 October 2016, attachment A, p. 1; and Essential Energy, *Essential Energy's framework and approach submission*, 25 October 2016, p. 1.

107 Ausgrid, *Request to replace Framework and Approach paper*, October 2016, p. 5;

108 NER, cl. 6.6.1.

109 NER, cl. 6.2.5(b).

110 NER, cl. 6.2.6(a).

111 NER, cl. 6.2.5(b).

112 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 capped price on some or all of the services.

A revenue cap sets a total annual revenue (TAR) for each year of the regulatory control period. A distributor complies 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 TAR. 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 TAR in future years. This operation occurs through an unders and overs account, whereby any revenue under recovery (over recovery) is added to (deducted from) the TAR in future years.

- tariff basket price control (weighted average price cap or WAPC)

A WAPC is a cap on the average increase in prices from one year to the next. This allows prices for different services to adjust each year by different amounts. For example, some prices may rise while others may fall, subject to the overall WAPC constraint. A weighted average is used to reflect that services may be sold in different quantities. Therefore, a small increase in the price of a frequently provided service must be offset by a large decrease in the price of an infrequently provided service. A distributor complies 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 TAR 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 TAR per unit of output.

- a combination of any of the above (hybrid).

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

In considering our preliminary positions on the control mechanisms for the NSW distributors' standard control services, we have only considered the continuation of the revenue cap, or adoption of price caps or an average revenue cap. We have not considered the other forms of control mechanisms for standard control services based on our previous considerations that they are not superior to either an average revenue cap or a revenue cap in addressing the factors set out in clause 6.2.5(c) of the NER. We have also considered a price cap control mechanism as it was proposed by AGL.[113]

We have not considered a schedule of fixed prices. We consider direct price control mechanisms do not provide the level of flexibility within the regulatory control period to manage distribution use of service charges shared across the broad customer base.

113 AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016.

We have not considered a WAPC as our previous considerations on this type of control mechanism noted the incentives for distributors to systematically recover revenue above efficient cost recovery resulting in higher bills for consumers.[114] We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.[115]

We have also not considered a hybrid approach as our previous considerations considered the higher administrative costs outweigh the potential benefits of this form of control.[116]

However, we are open to consideration on these other control mechanisms for making our final F&A where stakeholders consider an alternative control mechanism for the NSW distributors' standard control services would best address the factors set out in clause 6.2.5(c) of the NER.

In considering our preliminary positions on the control mechanisms for the NSW distributors' alternative control services, our consideration is based on whether there is reason to depart from the current price caps in terms of the factors set out in clause 6.2.5(c) of the NER.

2.2.1 Standard control services

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

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

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

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

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114 For example, see: AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 82 and AER, *Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, p. 78.

115 NEL, s. 7.

116 For example, see: *AER, Final framework and approach for Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 86.

The basis of the control mechanism for standard control services must be of the prospective CPI–X form or some incentive-based variant.[117]

Section 2.3 sets out our consideration of each of the above factors in determining our preliminary positions of the form of control mechanisms for standard control services.

2.2.2 Alternative control services

In determining a control mechanism to apply to alternative control services, we must have regard to the factors in clause 6.2.5(d) of the NER:

- 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 for us, the distributor and users or potential users
- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination
- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)
- any other relevant factor.

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. It also better promotes the national electricity objective by ensuring that customers only pay for services they use. Cost reflective prices also allow distributors to make efficient investment and demand side management decisions.

We must state what the basis of the control mechanism is in our distribution determination.[118] This may utilise elements of Part C of chapter 6 of the NER with or without modification. For example, the control mechanism may use a building block approach or incorporate a pass through mechanism.[119]

Section 2.4 sets out our consideration of each of the above factors in determining our preliminary positions of the form of control mechanism for alternative control services.

2.3 AER's reasons — control mechanism and formulae for standard control services

Our preliminary position is to maintain a revenue cap for the NSW distributors' standard control services for the 2019–24 regulatory control period. We consider the application of a

117 NER, cl. 6.2.6(a).
118 NER, cl. 6.2.6(b).
119 NER, cl. 6.2.6(c).

revenue cap control mechanism best meets the factors set out under clause 6.2.5(c) of the NER.

We consider that a revenue cap will result in no additional administrative costs and allow for consistency of regulatory arrangements for standard control services both across regulatory periods and across jurisdictions.

We also consider that a revenue cap will result in benefits to consumers through a higher likelihood of revenue recovery at efficient costs and will provide better incentives for demand side management. Furthermore, our recent approach to the operation of the revenue cap has reduced the magnitude of overall price instability during a regulatory control period, which has been a concern in the past. We provide our consideration of these issues below.

2.3.1 Efficient tariff structures

In deciding on a control mechanism, the NER requires us to have regard to the need for efficient tariff structures.[120] We consider tariff structures are efficient if they reflect the underlying cost of supplying distribution services.

Our preliminary position is that it is likely that efficient tariff structures can be developed and implemented under all types of control mechanisms. We note our recent assessment of distributors' tariff structures has demonstrated that efficient tariff structures have been developed and will be implemented under both average revenue cap and revenue cap control mechanisms.

Previously, our considerations on the interaction between a control mechanism and its ability to deliver efficient tariff structures during a regulatory control period relied solely on the incentive properties of the different types of control mechanisms.[121] However, recent changes to the NER now require us to undertake a supplementary assessment of the efficiency of a distributor's tariff structures which are to be set out in a tariff structure statement. Therefore, consideration of the interaction between control mechanisms and efficient tariff structures should also be informed by our assessment of a distributor's tariff structure statement.

The requirement for distributors to prepare tariff structure statements is new. It arises from a significant process of reform to the NER governing distribution network pricing. The purpose of the reforms is to empower customers to make informed choices by:

- Providing better price signals—tariffs that reflect what it costs to use electricity at different times so that customers can make informed decisions to better manage their bills.

120 NER, cl. 6.2.5(c)(1).

121 For example, see: AER*, Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, pp. 79–81 and AER, *Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, pp. 76–77.

- Transitioning to greater cost reflectivity—requiring distributors to explicitly consider the impacts of tariff changes on customers, and engaging with customers, customer representatives and retailers in developing network tariff proposals over time.
- Managing future expectations—providing guidance for retailers, customers and suppliers of services such as local generation, batteries and demand management by setting out the distributor's tariff approaches for a set period of time.

A distributor's tariff structure statement sets out the tariff structures it can apply over a regulatory control period.[122] The tariff structure statement should show how a distributor applied the distribution pricing principles[123] to develop its tariff structures and the indicative price levels of tariffs for the coming five year regulatory control period. The network pricing objective of the distribution pricing principles is the focus for a distributor when developing its network tariffs. The objective is that:[124]

> the tariffs that a distributor charges for provision of direct control services to a retail customer should reflect the distributors' efficient costs of providing those services to the retail customer.

We must approve a tariff structure statement unless we are reasonably satisfied it will not comply with the distribution pricing principles or other relevant requirements of the NER.[125]

Generally, a distributor is required to submit a tariff structure statement when submitting its regulatory proposal.[126] However, the NER permitted submission of the initial tariff structure statements outside the regulatory proposal process due to the timing of the rule changes.[127] In February 2017, we made final decisions on the initial tariff structure statements for ActewAGL and the distributors in Queensland, New South Wales and South Australia.

Our assessment of these initial tariff structure statements and the tariff structures contained within found that many distributors were introducing forms of more cost reflective tariff structures such as demand based tariffs. In this initial assessment we found no evidence to suggest that ActewAGL's average revenue cap or the revenue caps applied by other distributors inhibited the ability to develop or implement efficient tariff structures. Therefore, with regard to efficient tariff structures, we presently consider that they can occur under both average revenue cap and revenue cap control mechanisms. On this basis, we also consider efficient tariff structures are likely to occur under all forms of control mechanisms, including price caps.

While our consideration of efficient tariff structures does not necessarily indicate a revenue cap should be favoured over an average revenue cap or price caps, our decision on a

122 NER, cl. 6.18.1A(a)(3).
123 This is a reference to the NER' *pricing principles for direct control services*, alternatively described in this paper as the "distribution pricing principles"; NER, cl. 6.18.5(e)–(j).
124 NER, cl. 6.18.5(a).
125 NER, cl. 6.12.3(k).
126 NER, cl. 6.8.2(a).
127 NER, cl. 11.73.

control mechanism needs to be weighed against the other factors under clause 6.2.5(c) of the NER.

We note that tariff reform brought about by the tariff structure statements is still in its infancy. We may revisit the interaction between a control mechanism and efficient tariff structures for future F&A's.

2.3.2 Administrative costs

In deciding on a control mechanism, the NER requires us to have regard to the possible effects of the control mechanism on administrative costs.[128] We consider, where possible, a control mechanism should minimise the complexity and administrative burden for us, the distributor and users.

Generally, we consider there is little difference in administrative costs between control mechanisms under the building block framework in the long run. However, we consider the continuation of a revenue cap control mechanism to the NSW distributors' standard control services would best address clause 6.2.5(c)(2) of the NER. The continuation of a revenue cap would impose no additional administrative costs for us, the NSW distributors or users.

In contrast, additional administrative costs will be incurred by at least the NSW distributors and us in transitioning from a revenue cap to a price cap or alternative form of control mechanism. For example, new tariff models would need to be developed for annual pricing proposals to demonstrate compliance with the new control mechanism. Therefore, we consider the continuation of a revenue cap is superior in meeting clause 6.2.5(c)(2) of the NER.

2.3.3 Existing regulatory arrangements

In deciding on a control mechanism, the NER requires us to have regard to the regulatory arrangements applicable to the relevant service immediately before the commencement of the distribution determination.[129] We note maintaining a revenue cap control mechanism for the NSW distributors' standard control services provides for consistent regulatory arrangements for these services across regulatory control periods. Therefore, we consider the continuation of a revenue cap control mechanism is superior in meeting clause 6.2.5(c)(3) of the NER than an alternative control mechanism.

2.3.4 Desirability of consistency between regulatory arrangements

In deciding on a control mechanism, the NER requires us to have regard to the desirability of consistency between regulatory arrangements for similar services both within and beyond

[128] NER, cl. 6.2.5(c)(2).
[129] NER, cl. 6.2.5(c)(3).

the relevant jurisdiction.[130] We consider the continuation of a revenue cap control mechanism for the NSW distributors' standard control services provides for consistent regulatory arrangements for these services across jurisdictions.

We note that apart from ActewAGL, currently all other electricity distributors' who are subject to economic regulation under the NER have a revenue cap control mechanism applied to their standard control services. Therefore maintaining the NSW distributors' revenue cap control mechanism will ensure consistent regulatory arrangements for these services across most jurisdictions.

However, we note our preliminary position in the preliminary F&A for ActewAGL for the 2019–24 regulatory control period is to transition the control on ActewAGL's standard control services to a revenue cap. Should this occur, then all distributors' standard control services will be subject to a revenue cap control mechanism.

We note price caps are not applied to standard control services in any jurisdiction. Therefore, we consider the continuation of a revenue cap control mechanism is superior in meeting clause 6.2.5(c)(4) of the NER than an alternative control mechanism.

2.3.5 Revenue recovery

We consider that a control mechanism should give a distributor an opportunity to recover efficient costs. We also consider that a control mechanism should limit revenue recovery above such costs. Revenue recovery above efficient costs results in higher prices for end users. Further, allocative efficiency is reduced when a distributor recovers additional revenue from price sensitive services through prices above marginal cost.[131]

AGL submitted that we review the control on TasNetworks' revenues in light of uncertainty around future network demand and utilisation.[132] AGL posited a price cap control would better align prudent expenditure and cost minimisation with maintaining network utilisation.

Generally, we consider that a revenue cap provides a high likelihood of efficient cost recovery. Under a revenue cap, revenue recovery is fixed and unrelated to energy sales. Similarly, costs for distributors are largely fixed and unrelated to energy sales. Therefore, our view is that a revenue cap is likely to lead to efficient cost recovery.

We also consider that under a revenue cap that distributors have an incentive to reduce their costs because their revenues are assured during the regulatory control period. These lower costs can be shared with customers in future regulatory control periods. Therefore, we consider a revenue cap adequately addresses AGL's concerns that the control mechanism should align prudent expenditure and cost minimisation with maintaining network utilisation.

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130 NER, cl. 6.2.5(c)(4).

131 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.

132 AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016, p. 2.

In contrast, we consider that control mechanisms where revenue depends on energy sales (such as average revenue caps or price caps) provides distributors with incentives to understate sales forecasts and adjust tariffs to incur revenues above efficient cost recovery.[133] The systematic recovery of revenue above efficient cost recovery results in higher bills for consumers.[134] We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.[135]

Therefore, in terms of efficient revenue recovery, on balance we considered that a revenue cap control mechanism better reflects the national electricity objective than those that rely on energy sales.[136]

2.3.6 Pricing flexibility and stability

Price flexibility enables a distributor to restructure its tariffs to meet changes in the environment of operating an electricity distribution network during a regulatory control period. Price stability is important because it affects consumers’ ability to manage bills and retailers' ability to manage risks incurred from changes to network tariffs which they then package into retail plans for customers.

We consider price flexibility is primarily influenced by the distribution pricing principles and the side constraint. Therefore, price flexibility is similar for all control mechanisms as they are subject to the same distribution pricing principles and the same side constraint.

In terms of price stability, some control mechanisms are more likely to deliver stable prices than others. However, price instability can occur under all control mechanisms because the NER require various annual price adjustments regardless of the control mechanism.[137]

Within a regulatory control period, we consider an average revenue cap or price caps will deliver more overall price stability than a revenue cap. The increased instability under a revenue cap occurs because, future revenues and tariffs are adjusted to account for the difference between the actual revenue recovered and the TAR. These differences are due to the variations between forecast and actual sales volumes. As noted by AGL, under a revenue cap falling demand creates price increases.[138] The reverse happens with increasing demand. The true up of this under or over recovery of revenue is calculated in the unders and overs account.

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133 For example, see: *AER, Preliminary positions: Framework and approach paper ActewAGL—Regulatory control period commencing 1 July 2014*, pp. 64–67; AER,

134 For example, see: AER, *Final framework and approach for the Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 82 and AER, *Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, p. 78.

135 NEL, s. 7.

136 NEL, s. 7.

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

138 AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016, p. 2.

Typically there is a two year lag between the year the under or over recovery of revenue occurs (year t–2) and the year in which audited accounts can be relied upon to make an accurate revenue true up adjustment (year t). This lagged effect may cause price instability when an under (over) recovery of revenue in one year is followed by an over (under) recovery in the following year. In this scenario, price movements go in one direction for first year and then go in the opposite direction the following year.

We have somewhat addressed this issue in our recent determinations by applying a rolling unders and overs account which includes an additional true up for the estimated under and over recovery of revenues for the year in between (year t–1).[139] The inclusion of this estimated year helps smooth year on year revenue and tariff adjustments because the effects of the estimated year t–1 under or over recovery will have been largely accounted for when year t–1 becomes year t–2. That is, when year t–1 becomes year t–2 the adjustment to the TAR will only need to account for the difference between the estimated and actual under or over recovery and not the overall total under or over recovery.

In terms of instability across regulatory control periods, we consider an average revenue cap can result in greater price instability compared to a revenue cap.[140] This issue is particularly pronounced if a trend of falling demand and consumption has set in throughout the regulatory control period. This scenario would prompt a large upward adjustment in the X-factors (and hence prices) for the next regulatory control period under an average revenue cap. 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.

On balance, when weighing price flexibility and stability along with the other factors we have considered, our preliminary position is to maintain the NSW distributors' revenue cap control mechanism for standard control services. While we acknowledge a revenue cap has a higher likelihood of overall price instability during a regulatory control period, we consider our application of the rolling unders and overs account reduces the magnitude of this instability.

2.3.7 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.[141] 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.

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139 For example, see: AER, *Final Decision, CitiPower distribution determination 2016 to 2020: Attachment 14–Control mechanisms*, May 2016, Appendix A, pp. 18–19.

140 AER, *Preliminary positions: Framework and approach paper ActewAGL—Regulatory control period commencing 1 July 2014*, pp. 67–69.

141 Generally peak demand is referred to as the maximum load on a section of the network over a very short time period.

As stated above, AGL submitted that a price cap control mechanism be considered in light of uncertainty around network demand and utilisation.[142] However, we consider a revenue cap provides better signals for distributors to undertake demand side management.

Under a revenue cap a distributor's revenue is fixed over the regulatory control period. A distributor can therefore improve its financial position by reducing costs. This creates an incentive for a distributor to undertake demand side management projects that reduce total costs, even if that means the distributor does not build new assets or replace existing ones.[143] We consider this provides a stronger incentive for a distributor to undertake demand side management within a regulatory control period compared to a control mechanism that has expected revenues varying with overall sales such as a price cap.

Under an average revenue cap or price cap control mechanism, a distributor's revenues are linked more closely to actual volumes of electricity distributed. As a result, distributors' profits increase with sales if the marginal revenue is greater than the marginal cost of providing services. Demand side management may not be attractive for distributors if such projects result in less revenue because of falling demand or consumption.

2.3.8 Formulae for control mechanism

We are required to set out our proposed approach to the formulae that give effect to the control mechanisms for standard control services in the F&A paper.[144] In making a distribution determination, the formulae must be as set out in our final F&A, unless we consider that unforeseen circumstances justify departing from the formulae as set out in the F&A paper.[145] Below is proposed formula to apply to the NSW distributors' standard control services revenues. We consider that the formula gives effect to the revenue cap.

Figure 2.1 Preliminary positions revenue cap to be applied to the NSW distributors' standard control services

$$TAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$$ i = 1,…,n and j = 1,…,m and t = 1, 2…,5

$$TAR_t = AAR_t + I_t + B_t + C_t$$ t = 1, 2...,5

$$AAR_t = AR_t \times (1 + S_t)$$ t = 1

$$AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t) \times (1 + S_t)$$ t = 2,…,5

142 AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016, p. 2.

143 That is, demand side management projects that result in a reduction in future network expenditure greater than the cost of implementing the demand side management projects.

144 NER, clause 6.8.1(b)(2)(ii).

145 NER, cl. 6.12.3(c1).

where:

TAR_t is the total allowable revenue in year t.

p_t^{ij} is the price of component 'j' of tariff 'i' in year t.

q_t^{ij} is the forecast quantity of component 'j' of tariff 'i' in year t.

t is the regulatory year.

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

AAR_t is the adjusted annual smoothed revenue requirement for year t.

I_t is the sum of incentive scheme adjustments in year t. To be decided in the distribution determination.

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

C_t is the sum of approved cost pass through amounts (positive or negative) with respect to regulatory year t, as determined by the AER. It will also include any end-of-period adjustments in year t. To be decided in the distribution determination.

S_t is the s-factor for regulatory year t.[146] It will also incorporate any adjustments required due to the application of the STPIS in the 2017–19 regulatory control period consistent with the AER's STPIS.[147]

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[148] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1
>
> divided by

146 The meaning for year "t" under the price control formula is different to that in Appendix C of STPIS. Year "t+1" in Appendix C of STPIS is equivalent to year "t" in the price control formula of this decision.

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

148 If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2

minus one.

For example, for 2020–21, year t–2 is the December quarter 2018 and year t–1 is the December quarter 2019.

X_t is the X-factor in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. To be decided in the distribution determination.

2.4 AER's reasons — control mechanism for alternative control services

Our preliminary position is to apply caps on the prices of individual services (price caps) in the 2019–24 regulatory control period to all of the NSW distributors' alternative control service.[149] We propose classifying the following services as alternative control services:

- type 5-7 metering services
- public lighting services
- ancillary services.

We note the NSW distributors' alternative control services are currently subject to price cap regulation. The continuation of these price caps over the 2019–24 regulatory control period best meets the factors set out under clause 6.2.5(d) of the NER.

Unlike standard control services, the NER is not prescriptive on the basis of the control mechanism for alternative control services.[150] For example, the price caps could be based on a building block approach, or a modified building block cost build up. We have set out our preliminary position formulae that will give effect to the price cap control mechanisms in figure 2.2 and figure 2.3 below. However, it is at the distributor's discretion as to the approach it undertakes to develop its initial prices.

Prices for certain ancillary network services (quoted services) will be determined on a quoted basis. Prices for quoted services are based on quantities of labour and materials with the quantities dependent on a particular task. For example, where a customer seeks a non-standard connection which may involve an extension to the network the distributor may only be able to quote on the service once it knows the scope of the work. Because of this uncertainty, our preliminary positions price cap formula for quoted services differs to that proposed to apply to metering and fee based services. Our quoted services price cap is consistent with the approach we have adopted in the past.

149 The Consumer Challenge Panel supported maintaining price caps for alternative control services. Consumer Challenge Panel - Sub Panel CCP4, Submission, 10 March 2015

150 NER, cl. 6.2.6(c).

Our preliminary consideration of the relevant factors is set out below.

2.4.1 Influence on the potential to develop competition

We consider a departure from the current price cap controls for the NSW distributors alternative control services would not have a significant impact on the potential development of competition. We consider the primary influence on competition development will be the classification of services as alternative control services. Chapter 1 discusses classification.

2.4.2 Administrative costs

Where possible, a control mechanism should minimise the complexity and administrative burden for us, the distributor and users. The continuation of price caps will impose no additional administrative costs for us, the NSW distributors or users. Additional administrative costs will be incurred at least to the NSW distributors and us if an alternative control mechanism was applied to these services.

2.4.3 Existing regulatory arrangements

We consider consistency across regulatory control periods is generally desirable. Our preliminary position maintains this regulatory consistency as it continues the application of price cap control mechanisms for the NSW distributors' alternative control services.

2.4.4 Desirability of consistency between regulatory arrangements

We consider consistency across jurisdictions is also generally desirable. Our preliminary position maintains this consistency across jurisdictions.

We note that apart from the Victorian distributor's metering services which are subject to a revenue cap, price cap control mechanisms are currently applied to the alternative control services for all other electricity distributors subject to economic regulation under the NER.

2.4.5 Cost reflective prices

We consider that price caps are more suitable than other control mechanisms for delivering cost reflective prices. To apply price caps to the prices, we estimate the cost of providing each service and set the price at that cost. This will enhance cost reflectivity on both competitive and non-competitive services.

2.4.6 Formulae for alternative control services

We are required to set out our proposed approach to the formulae that gives effect to the control mechanisms for alternative control services.[151] In making a distribution

[151] NER, cl. 6.8.1(b)(2)(ii).

determination, the formulae must be as set out in our final F&A, unless we consider that unforeseen circumstances justify departing from the formulae as set out in the F&A paper.[152]

Below are our preliminary positions price cap formulae which will apply to the NSW distributors' alternative control services.

Figure 2.2 Preliminary positions price cap formula to be applied to the NSW distributors' metering, public lighting and fee based services

$\overline{p}_t^i \geq p_t^i$ i=1,...,n and t=1, 2,…,5

$$\overline{p}_t^i = \overline{p}_{t-1}^i \times (1 + \Delta CPI_t) \times (1 - X_t^i) + A_t^i$$

Where:

$\overline{p}_t^i$ is the cap on the price of service i in year t.

p_t^i is the price of service i in year t. The initial value is to be decided in the distribution determination.

$\overline{p}_{t-1}^i$ is the cap on the price of service i in year t–1.

t is the regulatory year.

ΔCPI_t is the annual percentage change in the ABS consumer price index (CPI) All Groups, Weighted Average of Eight Capital Cities[153] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1
>
> divided by
>
> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2
>
> minus one.

For example, for 2020–21, year t–2 is the December quarter 2018 and year t–1 is the December quarter 2019.

152 NER, cl. 6.12.3(c1).

153 If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

X_t^i is the X factor for service i in year t. The X factors are to be decided in the distribution determination and will be based on the approach the distributor undertakes to develop its initial prices.

A_t^i is the sum of any adjustments for service i in year t. Likely to include, but not limited to adjustments for any approved cost pass through amounts (positive or negative) with respect to regulatory year t, as determined by the AER.

Figure 2.3 Preliminary positions price cap formula to be applied to the NSW distributors' quoted services

$$Price = Labour + Contractor\ Services + Materials$$

Where:

$Labour$ consists of all labour costs directly incurred in the provision of the service which may include labour on-costs, fleet on-costs and overheads. Labour is escalated annually by $(1+\Delta CPI_t)(1-X_t^i)$ where:

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[154] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1
>
> divided by
>
> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2
>
> minus one.

For example, for 2020–21, year t–2 is the December quarter 2018 and year t–1 is the December quarter 2019.

X_t^i is the X factor for service i in year t. The X factor is to be decided in the distribution determination and will be based on the approach the distributor undertakes to develop its initial prices.

$Contractor\ Services$ reflect all costs associated with the use of external labour including overheads and any direct costs incurred. The contracted services charge applies the rates

154 If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

under existing contractual arrangements. Direct costs incurred are passed on to the customer.

$Materials$ reflect the cost of materials directly incurred in the provision of the service, material storage and logistics on-costs and overheads.

3 Incentive schemes

This chapter sets out our preliminary position on the application of a range of incentive schemes to the NSW distributors for the 2019−24 regulatory control period. At a high level, our preliminary position is to apply the:

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

3.1 Service target performance incentive scheme

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

Our national distribution STPIS[155] provides a financial incentive to distributors to maintain and improve service performance. The STPIS aims to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributor's incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (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 customers[156] experiencing service below a predetermined level.[157]

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

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

156 Except where a jurisdictional electricity GSL requirement applies.

157 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 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
- 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.

NSW distributors can propose to vary the application of the STPIS in its regulatory proposal.[158] We can accept or reject the proposed variation in our determination. Each applicable year we will calculate NSW distributors' 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.[159] 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 began to apply to NSW distributors from 2015. Because this was the first time the NSW distributors were subject to this scheme, a lower level of financial risk to the distributors in terms of penalty or reward of ±2.5 per cent through an s-factor adjustment to the allowable revenue was applied. GSLs are provided for through the Independent Competition and Regulatory Commission (ICRC) GSL scheme, so the GSL component of the AER's STPIS does not apply.

3.1.1 AER's preliminary position

Our preliminary position is to continue to apply the national STPIS to the NSW distributors 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 the urban and short rural feeder categories
- set applicable parameters to be:
- set applicable reliability of supply (system average interruption duration index or SAIDI and system average interruption frequency index of SAIFI) and customer service (telephone answering) parameters

158 AER, *Electricity distribution network service providers – service target performance incentive scheme*, 1 November 2009, cl. 2.2.

159 AER, *Electricity distribution network service providers – service target performance incentive scheme*, 1 November 2009, cll. 2.5(d) and (e).

- 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 the AEMO's 2014 Value Of Customer Reliability Review final report.

Our proposed approach is not to apply the GSL component if NSW distributors remain subject to a jurisdictional GSL scheme.

AGL submitted that a revisit of the incentive schemes is required to ensure these schemes assist in incentivising the distributors to achieve efficiency.[160]

Ausgrid submitted minor modifications could be made to the STPIS and sought consultation on the customer service component of the STPIS over the medium to longer term.[161] Endeavour Energy supports the continued application of STPIS and sought a review on the application of the STPIS in response to concerns raised by stakeholders.[162] Essential Energy submitted that the 2019−24 F&A paper should be aligned with the 2015−19 F&A paper regarding the departures from the STPIS.[163]

In response, we are currently undertaking review on the national STPIS. We will consider issues raised by stakeholders during this process.

3.1.2 AER's assessment approach

The NER sets out certain requirements in relation to developing and implementing a STPIS.[164] These include:

Jurisdictional obligations

- consulting with the authorities responsible for the administration of relevant jurisdictional electricity legislation
- ensuring that service standards and service targets (including GSL) set by the scheme do not put at risk the distributor's ability to comply with relevant service standards and service targets (including GSL) specified in jurisdictional electricity legislation any regulatory obligations or requirements to which the distributor is subject.

160 AGL, *Re Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016

161 Ausgrid, *Letter to AER - Request to replace framework and approach paper*, 25 October 2016, p. 5.

162 Endeavour Energy, *Letter to AER - Request to update framework and approach paper for the next regulatory control period,* 25 October 2016, Attachment A, p. 3.

163 Essential Energy, *Letter to AER - Update to framework and approach paper for the 2019−24 regulatory control period*, 25 October 2016, p. 2.

164 NER, cl. 6.6.2(b).

Benefits to consumers

Taking into account:

- the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any penalty or reward under the scheme
- the willingness of the customer or end user 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 NER 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.[165]

3.1.3 Reasons for AER's preliminary position

Our reasons for applying the STPIS to NSW distributors in the next regulatory control period are set out below.

Jurisdictional obligations

In NSW, the Independent Pricing and Regulatory Tribunal (IPART) administers and monitors compliance with the distribution licence conditions set by the NSW Department of Trade and Investment. Our proposed approach to applying the STPIS in NSW is to not create duplication or compromise NSW distributors' ability to comply with the jurisdictional requirements. Our proposed approach is therefore to not apply the GSL component of our national STPIS while the GSL arrangements in the NSW remain in place. We will amend this position if the NSW Government advises that these arrangements will cease to apply.

Benefits to consumers

We are mindful of the potential impact of the STPIS on consumers. Under the NER, 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.[166]

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

166 NER, cl. 6.6.2(b)(3)(vi).

Under the STPIS, a distributor's 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 currently in our national STPIS are taken from studies conducted for the Essential Services Commission Victoria and Essential Services Commission of South Australia. [167]

In September 2014 AEMO completed analysis of the VCR across the NEM.[168] This analysis will impact on our future development and application of the STPIS. We stated in our final decision for NSW distributors' 2015-19 regulatory period, that we will apply the latest value for VCR through the distribution determination in calculating the incentive rates. This is because we consider the 2014 AEMO NSW and ACT VCR better reflects the willingness of customers to pay for the reliable supply of electricity in the ACT. We consider that this approach is still appropriate.

Our preliminary position is to apply the scheme standard level of revenue at risk for NSW distributors at ±5 per cent as we do not consider that a lower level would better meet the objectives of the STPIS.

NSW distributors may propose an alternative VCR estimate and revenue at risk, supported by details of the calculation methodology, research and customer consultation, in the regulatory proposal. We would be interested in feedback on whether adopting a lower level of revenue at risk under the STPIS applied to NSW distributors would better meet the objectives of the scheme.

We seek stakeholder submissions on what are considered the appropriate VCR value and the appropriate level of revenue at risk applicable to NSW distributors under the STIPIS.

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 and how it interacts with our other incentive schemes. This is discussed below.

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167 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.

168 AEMO, *Value of customer reliability review - Final report*, September 2014.

Defining performance targets

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

The NER require us to consider past performance of the distributor's network in developing and implementing the STPIS.[169] Our preferred approach is to base performance targets on NSW distributors' average performance over the past five regulatory years.[170] Using an average calculated over multiple years instead of applying performance targets based solely on the most recent regulatory year limits a distributor's incentive to underperform in the final year of a regulatory control period to make future targets less onerous.

Distributors will only receive a financial reward after actual improvements are delivered to the customers. More importantly, a distributor can only retain its rewards if it can maintain the reliability improvements on an ongoing basis. Once an improvement is made, the benchmark performance targets will be tightened in future years. That is, the distributors' reliability targets for future years will be based on the level of performance that they have achieved to date. The reward for their improved performance is paid to the distributor (by customers) for five years. After which, customers will retain the benefit of the reliability improvement.

If the reliability levels should fall in the future, the distributor will receive penalties for not meeting the tightened targets—hence, the reward previously paid to the distributor will be returned to customers if the reliability levels fall.

Our national STPIS limits variability in penalties and rewards caused by circumstances outside the distributor's 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.

Interactions with our other incentive schemes

In applying the STPIS we must consider any other incentives available to the distributor under the NER or relevant distribution determination.[171] In NSW the STPIS will interact with our expenditure and demand management incentive schemes.

The efficiency benefit sharing scheme (EBSS) provides a distributor 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.

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169 NER, cl. 6.6.2(b)(3)(iii).

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

171 NER, cl. 6.6.2(b)(3)(iv).

In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.[172]

The capital expenditure sharing scheme (CESS) rewards a distributor 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 NER require us to consider the possible effects of the STPIS on a distributor's incentives to implement non-network alternatives to augmentation.

From time to time, we receive suggestion that outages caused by non-network solutions not delivering the contracted outputs to be excluded from the calculation of actual performance under STPIS to facilitate the take up of non-network solution projects. We consider that such arrangement will transfer the financial risk of non-network solution operators to customers.

We consider that non-network solution operators and the distributor are the parties best placed to manage the risk rather than the customers. Further, as customers are the party who finally fund the non-network solutions adopted by the distributors through network charges, they should not become the party to bear the risk of non-performance of such projects.

The STPIS treats the reliability implications of network and non-network solutions symmetrically, neither encouraging nor discouraging non-network alternatives to augmentation. Hence, we consider the current incentive framework of the STPIS is adequate to encourage distributors to select appropriate network or non-network solutions to manage their networks.

3.2 Efficiency benefit sharing scheme

The EBSS is intended to provide a continuous incentive for a distributor to pursue efficiency improvements in opex, and provide for a fair sharing of these between a distributor and network users. Consumers benefit from improved efficiencies through lower regulated prices in future regulatory control periods.

Ausgrid and Essential Energy stated their view on whether the EBSS should apply in the 2019–24 regulatory period will depend on the outcome of the AER's judicial review application.[173] Endeavour Energy recommended we provide analysis supporting the economic rationale underpinning the scheme and clarify the interaction between the EBSS and benchmarking. It considered the EBSS should only be applied in conjunction with forecast opex being set using the revealed cost method.[174]

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

173 Ausgrid, *Request to replace the framework and approach paper*, 25 October 2016, p. 6. Essential Energy*, Request to replace the framework and approach paper*, Attachment A, 25 October 2016, p. 2.

174 Endeavour Energy, *Request to replace the framework and approach paper*, Attachment A, 25 October 2016, p. 6.

We address our position on the application of the EBSS in relationship to our proposed opex forecasting approach and benchmarking below. We also explain the rationale underpinning the scheme.

This section sets out our preliminary position and reasons on how we intend to apply the EBSS to the NSW distributors in the 2019–24 regulatory control period.

3.2.1 AER's preliminary position

We intend to apply the EBSS[175] to the NSW distributors for the 2019–24 regulatory control period.

Our distribution determinations for the NSW distributors for the 2019–24 regulatory control period will specify if and how we will apply the EBSS.

3.2.2 AER's assessment approach

The EBSS must provide for a fair sharing between a distributor and network users of opex efficiency gains and efficiency losses.[176] We must also have regard to the following factors in developing and implementing the EBSS:[177]

- 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 preliminary position

The EBSS applies to Endeavour Energy in the 2015–19 regulatory control period.[178] However, it does not currently apply to Ausgrid[179] or Essential Energy.[180]

We chose not to apply the EBSS because we considered we might not use the revealed cost method to forecast Ausgrid's or Essential Energy's opex in the 2019–24 regulatory control period.

175 AER, *Efficiency benefit sharing scheme*, 29 November 2013.
176 NER, cl. 6.5.8(a).
177 NER, cl. 6.5.8(c).
178 AER, *Electricity distribution network service providers, efficiency benefit sharing scheme*, 26 June 2008.
179 AER, *Ausgrid distribution determination 2015–19, final decision*, p.9-6.
180 AER, *Essential Energy distribution determination 2015–19, final decision*, p. 9-6.

At the time we made our determinations for the 2015–19 regulatory control period, economic benchmarking and other corroborating evidence indicated that Ausgrid's opex and Essential Energy's opex was higher than opex incurred by a benchmark efficient service provider. In our decisions,[181] we noted that Ausgrid and Essential Energy had just over three years before they submitted their next regulatory proposals. Consequently, it was uncertain whether, and to what extent, we were likely to rely on their revealed costs in the 2015–19 regulatory control period to forecast opex in the 2019–24 regulatory control period. It followed that if we were not going to use a revealed costs approach for forecasting opex in the 2019–24 regulatory control period, there was not a strong reason to apply the EBSS in the 2015–19 regulatory control period.

We will make our decision whether or not to apply the EBSS to the NSW distributors in the 2019–24 regulatory control period in our determinations. The decision to apply the EBSS will depend on whether we use the distributors' revealed costs in the 2019–24 regulatory control period to forecast opex in the 2024–29 regulatory control period.

Why we would apply the EBBS

This section set outs reasons why we would only apply the EBSS if we use a revealed cost forecasting approach to forecast opex for the 2024–29 regulatory control period.

The EBSS must provide for a fair sharing of efficiency gains and losses.[182] Under the scheme distributors and consumers receive a benefit where a distributor makes on ongoing reduction to its opex during a regulatory control period. Similarly, both share any ongoing increases in opex.

Under the EBSS, positive and negative carryovers reward and penalise distributors for efficiency gains and losses respectively.[183] The distributor retains any efficiency gains or losses it makes for the length of the carryover period through the ex-ante opex allowance and the carryover payments it receives. In this way, the EBSS provides a continuous incentive for distributors to achieve opex efficiencies. This is regardless of the year in which it makes the gain or loss.[184]

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

181 AER, *Ausgrid distribution determination 2015–19, final decision*, April 2015, Attachment 9, p. 9-9. *AER, Essential Energy distribution determination 2015–19, final decision*, April 2015, Attachment 9, p. 9-8.

182 NER, cl. 6.5.8(a).

183 NER, cll. 6.5.8(c)(3) and 6.5.8(a).

184 NER, cl. 6.5.8(c)(2).

The EBSS also leads to a fair sharing of efficiency gains and losses between distributors and consumers.[185] 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. An example that shows how the EBSS operates is set out in our explanatory statement to our EBSS. It illustrates how the benefits of a permanent efficiency improvement are shared approximately 30:70 between a network service provider and consumers.[186]

In implementing the EBSS we must also have regard to any incentives distributors may have to capitalise expenditure.[187] Where opex incentives are balanced with capex incentives, a distributor does not have an incentive to favour opex over capex, or vice-versa. The CESS is a symmetric capex scheme with a 30 per cent incentive power. This is consistent with the incentive power for opex when we use an unadjusted base year approach in combination with an EBSS. During the subsequent period when the CESS and EBSS are applied, incentives will be relatively balanced, and a distributor should not have an incentive to favour opex over capex or vice versa. We discuss the CESS further in section 3.3.

We must also consider the possible effects of implementing the EBSS on incentives for non-network alternatives:[188]

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.[189] 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 a distributor may otherwise receive a penalty for increasing opex without a corresponding reward for decreasing capex.[190]

185 NER, cl. 6.5.8(c)(1).

186 See also: AER, *Explanatory statement, Efficiency benefit sharing scheme for electricity network service providers*, Appendix A, 29 November 2013, pp. 25–26.

187 NER, cl. 6.5.8(c)(4).

188 NER, cl. 6.5.8(c)(5).

189 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.

190 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.

Why we would not apply the EBBS

This section set outs reasons why we would not apply the EBSS if we considered it was not likely that we would use a revealed cost forecasting approach to forecast opex for the 2024–29 regulatory control period.

The use of revealed opex in determining the opex allowance for the following period is a key factor in whether the EBSS will achieve its stated objective. If it is uncertain whether we will rely on a distributor's revealed costs in period one to forecast opex in period two, there will not be a strong reason to apply the EBSS in period one. For example, if Ausgrid's revealed costs in the 2015–19 regulatory control period are still higher than the opex incurred by a benchmark efficient service provider, we will be unlikely to use revealed costs to forecast opex for the 2019–24 regulatory control period. In that case, we will be unlikely to apply the EBSS, to avoid network users being worse off.

If a business considers we will substitute an opex forecast not based on the revealed cost in a single base year, it has an incentive to significantly underspend in the base year to maximise its revenues. That is, the business can increase its EBSS carryover knowing the underspend will not reduce its opex forecast for the following period.[191] In this case, the benefit to the distributor of reducing opex in the base year would be greater than the opex underspend. Consumers would not receive a share of the underspend and would in fact be worse off. This outcome is contrary to the NER which requires that the EBSS must provide for a fair sharing of efficiency gains and losses between a distributor and customers.[192]

3.3 Capital expenditure sharing scheme

The CESS provides incentives for distributors to undertake efficient capex throughout the regulatory control period by rewarding efficiency gains and penalising efficiency losses. Consumers benefit from improved efficiency through lower network prices in the future. This section sets out our proposed approach and reasons for our intention to apply version 1 (dated 29 November 2013) of the CESS to the distributors.

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

The CESS works as follows:

- We calculate the cumulative underspend or overspend amount for the current regulatory control period in net present value terms.

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191 In our explanatory statement to the EBSS, we discuss why we should exclude the expenditure categories not forecast using a single year revealed cost forecasting method from the EBSS to prevent network users being worse off. AER, *Explanatory statement - efficiency benefit sharing scheme November* 2013, pp. 18-19.

192 NER, cl.˙ 6.5.8(a).

- We apply the sharing ratio of 30 per cent to the cumulative underspend or overspend amount to work out what the distributor's share of any underspend or overspend should be.
- We calculate the CESS payments taking into account the financing benefit or cost to the distributor of any underspend or overspend amounts.[193] 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 to or subtracted from 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 the financing benefit or cost of any underspend or overspend amount, while consumers retain 70 per cent of the financing benefit or cost of any underspend or overspend amount.

3.3.1 AER's preliminary position

Our preliminary position is to apply the CESS, as set out in our capex incentives guideline,[194] to the NSW distributors in the next regulatory control period.

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:[195]

- make that decision in a manner that contributes to the capex incentive objective set out in the NER[196]
- consider the CESS principles,[197] capex objectives,[198] 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.

193 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.

194 AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9.

195 NER, cl. 6.5.8A(e).

196 NER, cl. 6.4A(a); the capex criteria are set out in cl. 6.5.7(c) of the NER.

197 NER, cl.6.5.8A(c).

198 NER, cl. 6.5.7(a).

3.3.3 Reasons for AER's preliminary position

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

The NSW distributors are 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.[199] The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.[200] We are also proposing to apply forecast depreciation, which we discuss further in chapter 5. In developing the CESS we took into account the capex incentive objective, capex criteria, capex objectives, and the CESS principles. We also developed the CESS to work alongside other incentive schemes that apply to distributors including the, STPIS, and DMIS.

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

Without a CESS the incentive for a distributor to spend less than its forecast capex declines throughout the period.[201] Because of this a distributor may choose to spend capex earlier, or spend 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 a distributor with an ex ante incentive to spend only efficient capex in each year of the regulatory control period. A distributor that makes an efficiency gain will be rewarded through the CESS. Conversely, a distributor that makes an efficiency loss will be penalised through the CESS. In this way, a distributor will be more likely to incur only efficient capex when subject to a CESS, so any capex included in the RAB is more likely to reflect the capex criteria. In particular, if a distributor is subject to the CESS, its capex is more likely to be efficient and to reflect the costs of a prudent distributor.

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

199 AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9.

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

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

Ausgrid supports the application of the CESS in the 2019-24 regulatory control period. However, Ausgrid consider the AER's Framework and Approach paper should be amended to clarify that the current CESS will apply to each year of the 2019-24 determination. [202] We can confirm that we propose to apply the CESS to each regulatory year of the 2019-24 regulatory control period.

Ausgrid also considers that the CESS should encourage the deferral of capital where opportunities arise and that generally customers receive lower prices when this occurs. We agree that the CESS should encourage the efficient deferral of capex. [203] However, we support the exclusion of rewards under the CESS in certain circumstances. In particular, CESS rewards should be potentially excluded where a capex underspend arises from the deferral of capex between regulatory control periods, and customers do not receive any benefit from this capex deferral. This issue was discussed as part of the development of the CESS (refer to our explanatory statement dated 29 November 2013).[204]

In addition, Ausgrid stated that it has concerns that our revenue determinations do not specify projects for which Ausgrid receives funding. Ausgrid further stated that we may wish to consider a mechanism to determine the projects which have been deferred as a result of the using a substitute forecast.[205] While Ausgrid has not directly referred to the relevance of this issue to the CESS, it is important to set out our approach to assessing the ex-ante capex forecasts.

Relevantly, as emphasised as part of the development of our guideline, while our forecast of capex for a regulatory control period is partly informed by our forecast of the prudent and efficient capex the network service provider will need to complete discrete projects or programs this is only to inform our total forecast of capex for the regulatory control period. Importantly, while we may consider certain projects and programs in forming a view on the total capex forecast, we do not determine which projects and programs the network service provider should or should not undertake. This is consistent with the incentive based regulatory framework. Once we approve total revenue, the network service provider is able to prioritise its capex program given its circumstances over the course of the regulatory control period. This means, a network service provider may choose to defer some discrete projects that we initially considered when forming our view of the total capex forecast for the regulatory control period. Conversely, it may also choose to bring forward other discrete projects that we had not previously assessed when setting the network service provider's forecast of capex for the regulatory control period. This means that it is not appropriate to consider our determinations as approving specific projects and programs.

Endeavour Energy stated that should we update the CESS and that an updated Guideline should incorporate the clarification provided by the AER in its recent final F&A for TransGrid.

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202 Ausgrid, *Letter to the AER - Request to replace framework and approach*, 25 October 2017, p. 7.

203 Ausgrid, *Letter to the AER - Request to replace framework and approach*, 25 October 2017, p. 7.

204 AER, *Explanatory statement, capital expenditure incentive guideline for electricity network service providers*, November 2013, pp.46-47.

205 Ausgrid, *Letter to the AER - Request to replace framework and approach*, 25 October 2017, p. 7.

Endeavour Energy stated that it expects the CESS will continue to apply in accordance with the clarification provided in the TransGrid F&A. We can confirm that the CESS would apply in accordance with the clarifications provided in the TransGrid final F&A.[206]

Essential Energy commented that it expects that the current version of the CESS will apply in the 2019−24 regulatory control period.[207]

3.4 Demand management incentive scheme and innovation allowance mechanism

This section sets out our preliminary approach and reasons for applying our new demand management incentive scheme (DMIS) and demand management allowance mechanism (DMIA) to NSW distributors in the next regulatory control period.

We apply a DMIS in our distribution determination for the current regulatory control period.[208] .

The AER's current DMIS consists of two parts. The first is the demand management innovation allowance (DMIA) which is incorporated into NSW distributors' revenue allowance for each year of the regulatory control period. NSW distributors prepare an annual report on their expenditure under the DMIA[209] in the previous year, which we then assess against specific criteria. The second element is a forgone revenue component, which allows a distributor to recover forgone revenues that are directly attributable to a non-tariff demand management project or program approved under the DMIA. Compensation for foregone revenue is not applied where a distributor is subject to a revenue cap rather than a price cap.

Currently only the DMIA (Part A of the scheme) applies to NSW distributors because in the current regulatory control period it is subject to a revenue cap form of control. As a revenue cap is expected to apply in the next regulatory control period, compensation for foregone revenue will not be relevant to NSW distributors in the next regulatory control period.

A recent rule change by the AEMC[210] has affected the NER requirements regarding the application of a demand management scheme. On 20 August 2015, the AEMC published its Demand Management Incentive Scheme Rule Determination as well as its accompanying Rule changes setting out amendments to establish the proposed demand management scheme. There are two parts of the framework under the NER, these being the Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance mechanism (DMIA).

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206 Endeavour Energy, *Letter to the AER - Request to update framework and approach for the next regulatory control period*, 25 October 2017, p. 2.

207 Essential Energy, *Letter to the AER to update framework and approach for the 2019−24 regulatory control period*, 25 October 2017, p. 2.

208 NER, version 52, cl. 6.6.3 (a).

209 The DMIA excludes the costs of demand management initiatives approved in our determination for the 2012–17 period.

210 AEMC, *Rule Determination: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, August 2015.

The goal of the new scheme is to provide distributors with an incentive to encourage efficient demand management, both in implementing commercially viable demand management initiatives and in conducting research and development.

Under the new Rule, the objective of the DMIS/DMIA is to provide distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. The objective under the version of the NER applicable to the current regulatory control period was to "provide incentives for Distribution Network Service Providers to implement efficient non-network alternatives, or to manage the expected demand for standard control services in some other way, or to efficiently connect Embedded Generators". The objective of the new DMIS is therefore different than for the previous demand management scheme under the rule change.

The DMIS and DMIA will not affect the classification of distribution services, the form of the control mechanisms as specified in this F&A paper, the formulas that give effect to those mechanisms, or the pricing of services provided by dual function assets.

We are currently developing its new scheme and allowance mechanism, and in January 2017 published its DMIS/DMIA Consultation paper.[211] We will continue the process of consultation, including with NSW distributors, for developing the DMIS and DMIS. At this stage, we expect to make the new DMIS and DMIA by 30 September 2017.

3.4.1 AER's preliminary position

Our preliminary position is to apply the new DMIS and DMIA developed consequent to the rule change in August 2015 to NSW distributors in the next regulatory control period. That is, in the 2019 distribution determination for NSW distributors we will apply our new DMIS and DMIA currently being developed under a separate process, as noted above.[212]

3.4.2 AER's assessment approach to the DMIS

The NER require us to take several factors into account in developing and implementing a DMIS for NSW distributors.[213] These are:

DMIS Objective

- the DMIS should provide NSW distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management

211 AER, *Consultation Paper- Demand management incentive scheme and innovation allowance mechanism*, January 2017

212 This approach is supported by Endeavour Energy. See: Endeavour Energy, *Letter to the AER - Request to update framework and approach for the next regulatory control period*, 25 October 2017, p. 2. Ausgrid and Essential Energy noted that we are currently developing a new DMIS/DMIA. See: Ausgrid, *Letter to the AER - Request to replace framework and approach*, 25 October 2017, p. 7; Essential Energy, *Letter to the AER to update framework and approach for the 2019−24 regulatory control period*, 25 October 2017, p. 2.

213 NER, cl. 6.6.3(c).

Benefits to consumers

- the DMIS should reward NSW distributors for implementing relevant non-network options will deliver net cost savings to electricity consumers

Balanced incentives

- the DMIS should balance the incentives between expenditure on network options and non-network options relating to demand management
- the DMIS should take into account the net economic benefits delivered to all those who produce, consume and transport electricity in the market associated with implementing relevant non-network options
- the level of incentive the DMIS provides should be reasonable considering the long term benefit to retail customers.
- the DMIS should not include costs that are recoverable from another source, including under a relevant distribution determination
- the DMIS should not impose penalties on distributors
- the length of a regulatory control period should not limit the DMIS's incentives if this would not contribute to achieving the objective of the DMIS.

3.4.3 Reasons for AER's preliminary position on DMIS

This section outlines the reasons for our preliminary position to apply the DMIS to NSW distributors in the next regulatory control period.

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. Peak demand periods are typically brief and infrequent, but network infrastructure is built to operate during these peak periods without service interruptions. Hence, at other times there is significant redundant 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 modify the drivers of network usage, including reducing peak demand or changing the demand profile.[214] Demand management that effectively reduces network utilisation during peak usage periods can be an economically efficient way of deferring the need for network augmentation.

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[214] For example, agreements between distributors and consumers to switch off loads at certain times or allowing distributors to directly control consumer usage via load control devices reduces the demand for power drawn from the distribution network at peak times.

DMIS Objective

The DMIS must be designed so it can provide an incentive to a distributor to undertake non-network initiatives relating to demand management. The development of such incentives will need to consider the impacts of control mechanisms in the provision of incentives, that the design of the DMIS will ensure that non-network options do relate to and are likely to achieve demand management outcomes, and that such initiatives are cost efficient. A range of mechanism is being considered in developing a scheme that would contribute to the achievement of the DMIS objective.[215] The mechanisms are discussed in our DMIS review Discussion Paper.

Benefits to consumers

Customers ultimately will pay for any demand management incentives; therefore the rewards for demand management should target implementing non-network projects that will bring nett cost savings to retail customers[216]. The NER recognise that these nett cost savings to retail customers could be via the nett economic benefits delivered from implementing relevant non-network options[217] so we must remain mindful of the potential impact of the DMIS on consumers. The DMIS will be designed so that the long term benefits expected to result from the scheme exceed the costs to consumers resulting from any associated adjustment to regulated revenues. It is recognised though that the operation of the scheme may result in benefits that accrue over multiple periods. We recognise that the DMIS operation may involve consideration of the benefits and costs of implementing alternative options.

Balanced incentives

We intend to assess projects, for which distributors apply for DMIS funding, using an appropriate set of criteria that will balance the incentives between expenditure on network options and non-network options relating to demand management. The DMIS must also be designed so the costs to consumers resulting from the associated adjustment to regulated revenues do not exceed the long term benefits expected to result from the scheme, and the net economic benefits across all participants in the market are taken into account. In striking the appropriate balance, it must be recognised that the operation of the scheme may result in cost impacts within a regulatory control period where the benefits are unlikely to be revealed until later periods.

The objective of the DMIS design will be to select and encourage the implementation of demand management initiatives which are likely to provide long term efficiency gains to energy consumers that will outweigh any short term price increases.

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215 NER, cl. 6.6.3(c)(1).
216 NER, cl. 6.6.3(c)(2).
217 NER, cl. 6.6.3(c)(3).

The DMIS could promote selected initiatives which reduce investment in new infrastructure through either deferral of, or removal of the need for, network augmentation and or expansion expenditures. The DMIS could also be used to implement appropriate initiatives which result in a more efficient use of existing infrastructure.

We may design the DMIS to provide incentives for distributors to conduct demand management which are additions to those present within the broader regulatory framework.

The DMIS will be designed so all costs recovered from other sources will be excluded from incentive payments under the DMIS. The AER has had regard to the effect that the application of the scheme will have on the incentives created by the EBSS, CESS and STPIS, and vice versa in the development of the DMIS. The AER will also avoid the imposition of any penalties as part of the DMIS.

3.4.4 AER's assessment approach to the DMIA

The NER require us to take several factors into account in developing and implementing a DMIS for NSW distributors.[218] These are:

DMIS Objective

- The DMIA should provide NSW distributors with funding for research and development in demand management projects that have the potential to reduce long term network costs

Benefits to consumers

- Projects to which the Allowance Mechanism applies should have the potential to deliver ongoing reductions in demand or peak demand. They should be innovative, and should not be otherwise efficient and prudent non-network options that a distributor should have provided for in its regulatory proposal.
- The DMIA should provide a reasonable level of the allowance considering the long term benefit to retail customers. The DMIS should only provide funding that is not available from any another source, including under a relevant distribution determination
- The DMIA will require distributors to publish reports on the nature and results of demand management projects that are the subject of the allowance.

3.4.5 Reasons for AER's preliminary position on DMIA

This section outlines the reasons for our preliminary position to apply the DMIS to NSW distributors in the next regulatory control period.

Distributors have historically planned their network investment to provide sufficient capacity for the periods where the network elements reach maximum utilisation levels. Peak demand periods are typically brief and infrequent, but network infrastructure is built to operate during

[218] NER, cl. 6.6.3A(c).

these peak periods without service interruptions. Hence, at other times there is significant redundant capacity. Demand management that effectively reduces network utilisation during peak usage periods can be an economically efficient way of deferring the need for network augmentation and reducing long term network costs.

Research and development demand management projects will drive innovation in non-network solutions and have the potential to reduce long term network costs.

DMIA Objective

The revised NER has resulted in a modification of the objective of the allowance component of the demand management scheme, so we will design the DMIA to provide funding for research and development in demand management projects that have the potential to reduce long term network costs.

We will consider methods to encourage the selection of research and development projects which have the potential to reduce long term network costs via demand management methods.

Benefits to consumers

The DMIA design will ensure projects are selected for funding that are clearly aimed at implementing non-network options that will reduce demand or peak demand, and that have the potential to reduce long term network costs.

The DMIS design will ensure selection of projects that are innovative and would not be otherwise efficient and prudent non-network options that a distributor should have provided for in its regulatory proposal.

We consider there will be merit in clarifying the definition of innovative projects and of non-network projects, and for the development of criteria for assessment of projects as part of the designing of the DMIA. For example, clarification of innovative tariff trials may be required.

The DMIS will be designed so only funding is supplied which is not available from any another source, including under a relevant distribution determination, and this will form an assessment criteria for projects.

The design of the DMIA will require distributors to publish reports on the nature and results of demand management projects that are the subject of the allowance. Publication of such reports enables the knowledge gained from DMIA projects to be leveraged by other industry participants, with potentially greater consumer benefits.

4 Expenditure forecast assessment guideline

This chapter sets out our intention to apply our expenditure forecast assessment guideline (the EFA guideline)[219] including the information requirements applicable to NSW electricity distribution network service providers for the 2019−24 regulatory control period. We propose applying the EFA guideline as it sets out our expenditure forecast assessment approach developed and consulted upon during the Better Regulation program. The EFA guideline outlines the assessment techniques we will use to assess a distributor's proposed expenditure forecasts, and the information we require from the distributor.

The EFA guideline utilises a nationally consistent reporting framework allowing us to compare the relative efficiencies of distributors and decide on efficient expenditure allowances. The NER require NSW electricity distributors to advise us by 30 November 2017 of the methodology they propose to use to prepare their forecasts.[220] In the final F&A we must advise whether we will deviate from the EFA guideline.[221] This will provide the NSW distributors clarity on how we will apply the EFA guideline and the information they should include in their regulatory proposals. This contributes to an open and transparent process and provides stakeholders, as well as the NSW electricity distributors, with predictability of our assessment, however circumstances may change that require us to reconsider our position.

The EFA guideline contains a suite of assessment/analytical tools and techniques to assist our review of regulatory proposals by network service providers. We intend to have regard to 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.[222]

We exercise our judgement in determining the extent to which we use a particular technique in assessing a regulatory proposal. When assessing a regulatory proposal we use the techniques we consider appropriate depending on the specific circumstances of the determination. The guideline is flexible and recognises that we may employ a range of different estimating techniques to assess an expenditure forecast.

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219 We were required to develop the EFA guideline under clauses 6.4.5 and 11.53.4 of the NER. We published the guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864.

220 NER, cll. 6.8.1A(b)(1).

221 NER, cl. 6.8.1(b)(2)(viii).

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

The NSW distributors have raised concerns with our benchmarking methodology and approach, which is currently subject to judicial review.[223] We welcome the NSW distributors' and stakeholders' submissions to the preliminary F&A paper on the application of the current EFA guideline.

[223] Ausgrid, *Letter to the AER - Request to replace framework and approach*, 25 October 2017, p. 8; Endeavour Energy, *Letter to the AER - Request to update framework and approach for the next regulatory control period*, 25 October 2017, p. 8; Essential Energy, *Letter to the AER to update framework and approach for the 2019−24 regulatory control period*, 25 October 2017, p. 2.

5 Depreciation

As part of the process of rolling forward a distributor's RAB to the start of the next regulatory control period, we update the RAB for actual capex incurred during the current regulatory control period and also adjust for depreciation. This chapter sets out our preliminary approach on the form of depreciation to be used when the NSW distributors' RABs are rolled forward to the commencement of the 2024–29 regulatory control period.

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

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

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

Consumers benefit from improved efficiencies through lower regulated prices. Where a CESS is applied, using forecast depreciation maintains the incentives for distributors to pursue capex efficiencies, whereas using actual depreciation would increase these incentives. There is more information on depreciation as part of the overall capex incentive framework in our capex incentives guideline.[224] In summary:

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

The incentive from using actual depreciation to roll forward the RAB also varies with the life of the asset. Using actual depreciation will provide a stronger incentive for the distributor to underspend capex on shorter lived assets compared to longer lived assets as this will lead to a relatively larger increase in the RAB. Use of forecast depreciation, on the other hand, leads to the same incentive for capex regardless of asset lives. This is because using forecast depreciation does not affect the distributor's incentive on capex as the distributor does not lose the full cost of any overspend and is not able to keep all the benefits of any

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

underspend. To this end, using forecast depreciation means the capex incentive is focussed on the return on capital.

5.1 AER's preliminary position

Our preliminary position is to use the forecast depreciation approach to establish the RAB at the commencement of the 2024–29 regulatory control period for the NSW distributors. We consider this approach will provide sufficient incentives for the NSW distributors to achieve capex efficiency gains over the 2019–24 regulatory control period.

5.2 AER's assessment approach

We must decide for 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.[225]

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.[226] Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:[227]

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

5.3 Reasons for AER's preliminary position

Consistent with our capex incentives guideline, we propose to use the forecast depreciation approach to establish the RAB for the NSW distributors at the commencement of the 2024–29 regulatory control period. We note that the NSW distributors are supportive of using the forecast depreciation approach.[228]

We had regard to the relevant factors in the NER in developing the approach for deciding on the form of depreciation set out in our capex incentives guideline.[229]

225 NER, cl. S6.2.2B.
226 NER, cl. 6.4A(b)(3).
227 NER, cl. S6.2.2B.
228 Essential Energy, *Letter to AER: Update to Framework and Approach paper for the 2019–24 regulatory control period*, 25 October 2016; Endeavour Energy, *Letter to AER: Request to update Framework and Approach paper for the next regulatory control period—Attachment A*, 25 October 2016; Ausgrid, *Letter to AER: Request to replace Framework and Approach paper*, 25 October 2016, p. 8.
229 AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 10–12.

Our approach is to apply forecast depreciation except where:

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

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

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

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

The opening RAB at the commencement of the 2019–24 regulatory control period will be established using forecast depreciation, as stated in our previous determination that applies to the NSW distributors for the 2015–19 regulatory control period. The use of forecast depreciation to establish the opening RAB for the commencement of the 2024–29 regulatory control period therefore maintains the current approach. The NSW distributors are currently subject to a CESS and we propose to continue to apply the CESS in the 2019–24 regulatory control period. We discuss this in section 3.3.

For the NSW distributors, we consider the incentive provided by the application of the CESS in combination with the use of forecast depreciation and our other ex post capex measures should be sufficient to achieve the capex incentive objective.[230] Our ex post capex measures are set out in the capex incentives guideline. The guideline also sets out how all our capex incentive measures are consistent with the capex incentive objective.

230 AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 13–19 and 20–21.

6 Dual function assets

Dual–function assets are high voltage transmission assets forming part of the distribution network. Transmission network service providers usually operate these assets. Considering transmission assets as part of a distribution determination avoids the need for a separate transmission proposal. Where a network service provider owns, controls or operates dual-function assets, we are required to consider whether we should price these assets according to the transmission or distribution pricing principles.

Our preliminary decisions continue the current pricing approaches. Current approaches reflect dual function asset materiality compared to total assets and allow cost reflective pricing for benefitting customers. Our decisions are also consistent with distributors' preferences.

6.1 AER's preliminary position

Our final F&A decisions on dual function asset pricing are binding on us and on NSW distributors throughout the 2019–24 regulatory control period.

Ausgrid

Our preliminary decision is to apply transmission pricing to Ausgrid's dual function assets.[231] This is consistent with the current approach and Ausgrid's preferences.[232]

Endeavour Energy

Our preliminary decision is to apply distribution pricing to Endeavour Energy's dual function assets. This is consistent with the current approach and Endeavour Energy's preference.[233]

Essential Energy

The NER do not require us to make a decision for Essential Energy. It does not own, operate or control dual function assets.[234]

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231 Relevant services conform to the definition under cl. 6.24.2 of the NER.

232 Ausgrid, *Letter to AER - Request to replace framework and approach paper*, October 2016, p. 9.

233 Endeavour Energy*, Letter to AER - Request to AER to update the framework and approach for the next regulatory control period, Attachment A*, October 2016, p. 1.

234 Essential Energy, *Letter to AER - Update to framework and approach paper for the 2019-24 regulatory control period*, October 2016, p. 3.

Table 4 Dual function assets and pricing approaches

	Ausgrid	Endeavour Energy	Essential Energy
Dual function assets ($m)	$2,020 million	$227 million	0
Proportion of distribution Regulatory Asset Base (%)	14%	5%	0
Current regulatory period pricing	Transmission	Distribution	n/a
Service provider preference	Transmission	Distribution	n/a
AER preliminary position	Transmission	Distribution	n/a

6.2 Distributors' views

Ausgrid and Endeavour Energy submitted their preferences in favour of our preliminary positions.

6.3 AER's assessment approach

Dual function asset rules establish transmission pricing as the default approach where the assets form a material proportion of the distributor's regulatory asset base (RAB). The NER require us, in deciding pricing approaches, to consider impacts on distribution prices and consumption, production and investment. We may also account for other factors we consider relevant.

Our decisions on dual function assets incorporate two main stages. First, we must be satisfied that relevant assets conform to the NER definition. On this, we gave weight to distributor information and statements. Having satisfied ourselves on this first issue, we then considered alternative pricing approaches.

Distribution and transmission pricing represent different ways of recovering service costs. Under transmission pricing, distributors may allocate dual function asset costs to both a TNSP's broader customer base and the distributor's customers. However, under distribution pricing rules, distributors with dual function assets may not allocate costs to a TNSP.

Electricity supply costs transfer along the supply chain, or downstream, onto the next service provider in the process. Hence, generators pass generation costs to retailers who pass them to customers. In the same way, TNSPs pass their costs to distributors, who in turn pass those costs to retailers and then to customers. Costs may not be passed back up the supply chain from distributors to TNSPs, except under transmission pricing rules. Therefore, under distribution pricing rules, a distributor's own customers pay the full cost of dual function assets.

Because transmission networks are upstream of distribution networks, they usually service larger numbers of electricity consumers than distribution networks. Therefore, where TNSPs recover the same service costs, transmission pricing usually provides for lower per unit prices than distribution pricing. We note that this is not necessarily an appropriate outcome. The NER require us to determine efficient service costs. In principle, electricity consumers who stand to benefit from dual function assets should pay for those services.

In some cases, the potential transmission and distribution customer bases for cost recovery purposes are the same. In such cases, network service providers would recover dual function asset costs from the same number of customers. The AER expects that in such cases price impacts for individual customers under both pricing approaches would be equivalent.

We applied a three part test to determine application of either transmission or distribution pricing rules. Firstly, we considered the value of dual function assets as a proportion of the distributor's RAB. Secondly, we considered whether regulating prices under distribution rules rather than transmission would:

- result in materially different prices for distribution customers
- impact on future consumption, production and investment decisions.

Thirdly, we took into account other matters we considered relevant. Specifically, we considered cost reflectivity, or who benefits from the assets and administrative cost implications of changing the current approach. Customers benefitting from dual function assets should contribute to their cost recovery. The NER define dual function assets as supporting the higher voltage transmission network. Therefore, our default assumption is that a broader customer set than just the distributor's customers are benefiting from shared assets. We also consider that we should avoid administrative costs where possible. Finally, we consider the current approach should continue unless we identify sufficient reasons to change the approach.

6.4 Reasons for AER's preliminary position

For the following reasons our preliminary position is that transmission pricing will continue to apply to Ausgrid's dual function assets. At 14 per cent, the assets are clearly a material proportion of Ausgrid's RAB, justifying application of transmission pricing. Further, application of distribution pricing would materially impact Ausgrid's distribution customers and affect consumption, production and investment. In terms of cost reflectivity, Ausgrid's dual function assets support TransGrid's transmission network, so transmission pricing facilitates appropriate cost recovery. Additionally, maintaining the current transmission pricing approach avoids additional administrative costs.

For the following reasons, our preliminary position is that distribution pricing would continue to apply to Endeavour Energy's dual function assets. At 5 per cent of Endeavour Energy's RAB, these are significantly less material than is the case for Ausgrid. Additionally, Endeavour Energy submitted that its dual function assets form transmission exit assets supporting only its own distribution network. This means that even under transmission pricing rules, full asset costs would be allocated to Endeavour Energy distribution customers. Therefore, changing the pricing approach to transmission pricing would not have a material impact on distribution prices. Changing the approach would also incur administrative costs.

We are not required to decide a pricing approach for Essential Energy, as it does not operate dual function assets.

Ausgrid

Our preliminary position is that Ausgrid would continue to apply transmission pricing to its dual function assets.

Ausgrid operates assets conforming to the NER dual function asset definition. We reached this view, firstly, because Ausgrid reported that it currently operates assets conforming to the NER definition. As there are significant penalties for reporting incorrect information, we gave weight to Ausgrid's reported information. Secondly, Ausgrid's reported information is consistent with historic information on its dual function assets.

We then considered the materiality of dual function assets in terms of Ausgrid's RAB. At $2,020 million (nominal) or 14 per cent of Ausgrid's RAB, we consider Ausgrid's dual function assets are a material proportion of its RAB. The NER does not define 'material' in the context of dual function assets. We therefore applied its common meaning and considered the consumer price implications of this asset proportion. Removing such a proportion of Ausgrid's RAB would have a more than double-digit impact on customer prices. Such a price impact would clearly be significant or important to customers. As such, we consider 14 per cent is clearly a significant or important proportion of Ausgrid's total RAB.

We further consider that, wherever possible, end-use customers benefitting from specific network assets should bear the cost of those assets. Dual function asset rules, however, do not explicitly establish this principle. Rather, dual function asset rules are premised on transmission pricing being the default approach. To apply distribution pricing rules, a number of tests must be met, relating to asset proportions and consumer price impacts.[235] We therefore give weight to benefitting customers under our power to consider other issues.[236]

Under transmission pricing, dual function asset costs are appropriately directed to both Ausgrid's customers and the broader set of TransGrid customers. The NER define dual function assets as providing support to the higher voltage transmission network, in this case operated by TransGrid. Ausgrid reported it owns dual function assets. Our preliminary position is that Ausgrid's dual function assets are indeed supporting TransGrid's network,

235 NER, cl. 6.25(b) and (c).
236 NER, cl. 6.25(c)(3).

providing services both to Ausgrid and others. Under distribution pricing rules, only Ausgrid's customers would pay for its dual function assets. Therefore, substituting distribution pricing for the current transmission pricing approach would not be appropriate.

We further consider that changing from the current transmission pricing approach may also increase Ausgrid's administrative costs. This is because changing the pricing approach would require changes to Ausgrid's processes and systems. Such administrative costs give weight to maintaining the current approach.

Our preliminary position is therefore that the current pricing approach should be continued in the upcoming regulatory control period. This position is consistent with the current regulatory approach.

Endeavour Energy

Our preliminary position is that Endeavour Energy would continue to apply distribution pricing to its dual function assets.

Endeavour Energy operates assets conforming to the NER dual function asset definition. Again, we reached this view on the basis of information submitted to us by Endeavour Energy which is also consistent with historical information. At $227 million or 5 per cent of its RAB, Endeavour Energy's dual function assets are a smaller proportion of its RAB than other distributors' dual function assets. For reasons set out below, Endeavour Energy's RAB valuations are less relevant than in other contexts.

In terms of the price impact of the alternative pricing approaches, we gave weight to Endeavour Energy's views:[237]

> The AER confirmed its decision from the 2009-14 F&A paper that distribution pricing would continue to apply to Endeavour Energy's dual function assets in its Stage 1 2014-19 F&A paper. This was due to our dual function assets being an immaterial proportion of our overall regulated asset base. Further, these assets are dedicated to our distribution network meaning that separately pricing them as transmission assets would not have any material impact on our distribution prices. This is because these transmission charges would be wholly allocated to Endeavour Energy, which they currently are as part of our distribution network.
>
> We have updated the analysis provided to the AER in support of its decision in the 2014-19 F&A and attached it to this response. The updated analysis confirms that the relevant assets would remain an immaterial proportion of the overall asset base and be classified as exit equipment. Therefore, we consider there is no need to amend or replace the existing F&A in respect of this matter.

The NER specify that exit equipment, or exit assets, provide transmission 'prescribed exit services'. Such assets link a transmission network to a transmission customer, or group of customers. In other words, electricity 'exits' the transmission network via such assets. The NER specify that a TNSP operating those services must attribute related costs to benefiting

[237] Endeavour Energy*, Letter to AER - Request to AER to update the framework and approach for the next regulatory control period, Attachment A*, October 2016, p. 1.

customers. In this case, Endeavour Energy's distribution customers are the only beneficiaries of its dual function assets. Transmission pricing rules would therefore allocate the full cost of Endeavour Energy's dual function assets to its own distribution customers.

Endeavour Energy currently recovers full dual function asset costs from its distribution customers. Therefore, changing to transmission pricing would produce no material change in Endeavour Energy's distribution prices. Without an appreciable price difference, continuing distribution pricing would have little impact on future consumption, production and investment decisions.

We further consider that changing from the current distribution pricing approach may also increase administrative costs for Endeavour Energy. This is because changing the pricing approach would require changes to Endeavour Energy's processes and systems. Such administrative costs give weight to maintaining the current approach.

In light of the above, our preliminary decision is that distribution pricing should continue to apply. This position is also consistent with us giving weight to continuing the current approach.

Appendix A: Rule requirements for classification

We must have regard to four factors when classifying distribution services.[238]

- 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.[239]
- 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)[240]
- the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)[241]
- any other relevant factor.[242]

238 NER, cl. 6.2.1(c).
239 NEL, s. 2F.
240 NER, cl. 6.2.1(c)(2).
241 NER, cl. 6.2.1(c)(3).
242 NER, cl. 6.2.1(c).

The NER specify additional requirements for services we have regulated before.[243] They are:

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

We must have regard to six factors when classifying direct control services as either standard control or alternative control services.[244]

- the potential for development of competition in the relevant market and how the classification might influence that potential
- the possible effects of the classification on administrative costs of us, the distributor and users or potential users
- the regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made
- the desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction)
- the extent that costs of providing the relevant service are directly attributable to the customer to whom the service is provided, and
- any other relevant factor.[245]

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 NER.

243 NER, cl. 6.2.1(d).
244 NER, cl. 6.2.2(c).
245 NER, cl. 6.2.2(c).

Appendix B: Preliminary classification of NSW distribution services

Service group/Activities included	Further description (if any)	Current Classification 2014−19	Proposed classification 2019−24
Common distribution services			
Common distribution services (formerly 'network services')	The suite of services and activities involved in operating and distributing electricity to customers safely and reliably in accordance with the National Electricity Law, National Electricity Rules and NSW jurisdictional requirements as a participant in the NEM and holder of a NSW distribution operator’s licence. For example, this includes planning, designing, constructing, augmenting, maintaining, repairing, managing and operating the network and network demand for distributor purposes. Common distribution services involves, but is not limited to, the following activities: • regulatory and pricing planning • demand management planning • management of environmental issues • asset relocations (not at customer's request) • vegetation management • works to fix damage to the network (including emergency recoverable works) or supporting another distributor during an emergency event.	Standard control	Standard control

Service group/Activities included	Further description (if any)	Current Classification 2014−19	Proposed classification 2019−24
	• dial before you dig services • external stakeholder management • call centres, enquiries and billing • performance monitoring.		

Ancillary services

Service group/Activities included	Further description (if any)	Current Classification 2014−19	Proposed classification 2019−24
Design related services	Activities includes: • processing preliminary enquiries requiring site specific or written responses • provision of design information, design rechecking services in relation to connection and relocation works provided contestably. • specialist services where the design is non-standard, technically complex or environmentally sensitive and any enquiries related to distributor assets • assessing connection applications or a request to undertake relocation of network assets as contestable works and preparing offers.	Alternative control	Alternative control (specific monopoly service)
Contestable network commissioning and decommissioning	The commissioning and decommissioning of network equipment associated with ASP Level 1 contestable works. Includes equipment checks, tests and activities associated with setting or resetting network protection systems and the updating of engineering systems.	Alternative control	Alternative control (specific monopoly service)
Access permits and oversight	Activities include:	Alternative control	Alternative control

Service group/Activities included	Further description (if any)	Current Classification 2014−19	Proposed classification 2019−24
	• A distributor issuing access permits or clearances to work to a person authorised to work on or near distribution systems including high and low voltage. • A distributor issuing confined space entry permits and associated safe entry equipment to a person authorised to enter a confined space. A distributor providing access to switch rooms, substations and the like to a non-LNSP party who is accompanied and supervised by a distributor's staff member. May also include a distributor providing safe entry equipment (fall-arrest) to enter difficult access areas.		(specific monopoly service)
Notices of arrangement	Work of an administrative nature performed by a distributor where a local council requires evidence in writing from the distributor that all necessary arrangements have been made to supply electricity to a development. This may include receiving and checking subdivision plans and 88 B instruments, copying subdivision plans, checking and recording easement details, assessing supply availability, liaising with developers if errors or changes are required and preparing notifications of arrangement.	Alternative control	Alternative control (specific monopoly service)
Property services	Property tenure services related to obtaining deeds of agreement, deeds of indemnity, leases, easements or other property tenure in relation to property rights associated with connection or relocation. Conveyancing inquiry services relating to the provision of property conveyancing information at the request of a customer.	Alternative control	Alternative control (specific monopoly service)
Site establishment services	Site establishment services, including liaising with the Australian Energy Market Operator (AEMO) or market participants for the purpose of establishing NMIs in market systems, for new premises or for any	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included	Further description (if any)	Current Classification 2014−19	Proposed classification 2019−24
	existing premises for which AEMO requires a new NMI and for validation of and updating network load data. This includes processing and assessing requests for a permanently unmetered supply device.		
Networks safety services	Includes provision of traffic control services by the distributor where required, fitting of tiger tails, high load escort, night watch (private security and flood lighting services), de-energising wires for safe approach (e.g. for tree pruning).	N/A	Alternative control (potentially contestable)
Customer vegetation defect works	Work involved in managing and resolving pre-summer bush fire inspection customer vegetation defects where the customer has failed to do so.	N/A	Alternative control (specific monopoly service)
Network tariff change request	When a retailer's customer or retailer requests an alteration to an existing network tariff (for example, a change from a Block Tariff to a Time of Use tariff), the distributors conduct tariff and load analysis to determine whether the customer meets the relevant tariff criteria. The distributors also process changes in their IT systems to reflect the tariff change.	Alternative control	Alternative control (specific monopoly service)
Recovery of debt collection costs - dishonoured transactions	The incurrence of costs, including bank fees by a distributor resulting from the dishonour of a customer or ASP's cheques tendered in payment of network related services.	Alternative control	Alternative control (specific monopoly service)
Services provided in relation to a Retailer of Last Resort (ROLR) event	The distributors may be required to perform a number of services as a distributor when a ROLR event occurs. For example: Preparing lists of affected sites and reconciling data with AEMO listings, arranging estimate reads for the date of the ROLR event, preparing final invoices and miscellaneous charges for affected customers, extracting customer data, providing it to the ROLR and	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included	Further description (if any)	Current Classification 2014−19	Proposed classification 2019−24
	handling subsequent enquiries.		
Planned Interruption – Customer requested	Where the customer requests to move a planned interruption and agrees to fund the additional cost of performing this distribution service outside of normal business hours.	N/A	Alternative control (specific monopoly service)
Attendance at customers' premises to perform a statutory right where access is prevented.	A follow up attendance at a customer's premises to perform a statutory right where access was prevented or declined by the customer on the initial visit. This includes the costs of arranging, and the provision of, a security escort or police escort (where the cost is passed through to the distributor).	Alternative control	Alternative control (specific monopoly service)
Inspection services - Private electrical installations and alternative service providers (ASPs)	Inspection of and reinspection by a distributor of: • private electrical wiring work undertaken by an electrical contractor ASP contestable connection and relocation works including investigation, review and implementation of remedial actions that may lead to corrective and disciplinary action of an ASP due to unsafe practices or substandard workmanship.	Alternative control	Alternative control (specific monopoly service)
Authorisation of ASPs and associated administrative services	Includes annual authorisation of individual employees and sub-contractors of ASPs and additional authorisations at request of ASP and other administrative services performed by the distributor relating to work performed by an ASP	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included	Further description (if any)	Current Classification 2014−19	Proposed classification 2019−24
Metering services			
Type 1-4 metering services	Type 1 to 4 meters and supporting services are competitively available.[246]	Unclassified	Unclassified
Type 5 and 6 metering provision (before 1 July 2015)	Distributors may recover the capital cost of type 5 and 6 metering equipment installed before 1 July 2015.	Alternative control	Alternative control (specific monopoly service)
Type 7 metering services	Administration and management of type 7 metering installations in accordance with the NER and jurisdictional requirements. Includes the processing and delivery of calculated metering data for unmetered loads, and the population and maintenance of load tables, inventory tables and on/off tables.	Standard control	Standard control
Meter reading and testing	Meter reading and testing services include: • Special meter reading for type 5 and 6 meters and move in and move out metering reading (type 5 and 6 meters) • Type 5 meter final read on removed type 5 metering equipment • Meter test (for type 5 and 6 meter) • Types 5-7 non-standard meter data services • Type 5 and 6 current transformer testing	Alternative control	Alternative control (specific monopoly service)
Types 5 and 6 meter reading,	Meter maintenance covers works to inspect, test, maintain, repair and replace meters. Meter reading refers to quarterly or other regular	Alternative control	Alternative control (specific

[246] NER, cll. 7.2.3(a)(2) and 7.3.1.A(a)).

Service group/Activities included	Further description (if any)	Current Classification 2014−19	Proposed classification 2019−24
maintenance and data services	reading of a meter. Metering data services are those that involve the collection, processing, storage and delivery of metering data and the management of relevant NMI Standing Data in accordance with the Rules.		monopoly service)
Emergency maintenance of failed metering equipment not owned by the network	The distributor is called out by the customer due to a power outage where an external metering provider's metering equipment has failed or an outage has been caused by the metering provider and the distributor has had to restore power to the customer's premises. This may result in an unmetered supply arrangement at this site.	Alternative control	Alternative control (specific monopoly service)
Meter recovery - type 5 and 6 current transformer metering	At the request of the customer or their agent to remove a type 5 or 6 current transformer meter where a permanent disconnection has been requested.	N/A	Alternative control (specific monopoly service)
Distributor arranged outage for purposes of replacing metering	At the request of a retailer or metering coordinator provide notification to affected customers and facilitate the disconnection/reconnection of customer metering installations where a retailer planned interruption cannot be conducted.	N/A	Alternative control (specific monopoly service)
Site alteration service	Site alteration services updating and maintaining national metering identifier (NMI) and associated data in market systems	N/A	Alternative control (specific monopoly service)
NMI extinction fee	At the request of the customer or their agent processing a request for permanent disconnection and the extinction of a NMI in market systems	N/A	Alternative control (specific monopoly service)
Correction of metering and market billing data	Confirming or correcting metering or network billing information in market B2B or network billing systems, due to insufficient or incorrect information received from retailers or metering providers.	N/A	Alternative control (specific monopoly service)

Service group/Activities included	Further description (if any)	Current Classification 2014−19	Proposed classification 2019−24
Connection services			
Premises connection assets	Includes any additions or upgrades to the connection assets located on the customer's premises which are contestable (Note: excludes all metering services). Premises connection assets can be further described as: A. Design and construction of premises connection assets (where these services are provided contestably) B. Part design and construction of connection assets that are not available contestably (generally as a result of safety, reliability or security reasons). Those parts of project works that are performed and funded by the distributor.	A. Unclassified B. Standard control	A. Unclassified B. Standard control
Extensions	An enhancement required to connect a power line or facility outside the present boundaries of the transmission or distribution network owned or operated by a Network Service Provider that is: A. undertaken by an ASP on behalf of a customer B. undertaken by a customer but partly funded by a NSP (NSP contribution would be classified as a standard control service while the customer funded component of the service would be unclassified.) C. undertaken by a network service provider	A. Unclassified B. Unclassified/standard control based on contribution (see previous column) C. Standard control	A. Unclassified B. Unclassified/standard control based on contribution (see further description) C. Standard control
Augmentations	A. Any shared network enlargement/enhancement undertaken by a distributor which is not an extension B. Any shared network enlargement/enhancement undertaken by a	A. Standard control B. Unclassified/standard control based on contribution	A. Standard control B Unclassified/standard control based on contribution

Service group/Activities included	Further description (if any)	Current Classification 2014−19	Proposed classification 2019−24
	customer, but partly funded by a NSP (NSP contribution would be classified as a standard control service while the customer funded component of the service would be unclassified) C. Any shared network enlargement/enhancement undertaken by a customer	(see previous column) C. Unclassified	(see further description) C. Unclassified
Registered participant support services	Services and information provided by the distributor and proposed market participants associated with connection arrangements and agreements made under Chapter 5 of the NER.	N/A	Alternative control (specific monopoly service)
Site inspection	Site inspection services in order to determine the nature of the connection service sought by the connection applicant.	N/A	Alternative control (specific monopoly service)
Facilitation of generator connection and operation on the network	Includes connection/disconnection of generator to distributor's assets and any ongoing requirements to facilitate its operation.	N/A	Alternative control (potentially contestable)
Reconnections/Disconnections	Disconnection and/or reconnection services (some provided in accordance with the National Energy Retail Rules). For example: • Disconnection visit (site visit only) • Disconnection visit (disconnection completed - technical) • Pillar box/pole top disconnection - completed • Reconnection/disconnection outside of business hours • Vacant property - site visit • Shared service fuse replacement • Rectification of illegal connections	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included	Further description (if any)	Current Classification 2014–19	Proposed classification 2019–24
	• Temporary connections • Remove or reposition connection • Single phase to three phase		
Public lighting			
Public lighting	Provision, construction and maintenance of public lighting and emerging public lighting technology	Alternative control	Alternative control
Unregulated distribution services			
Distribution asset rental	Rental of distribution assets to third parties (e.g. office space rental, pole and duct rental etc.).	N/A	Unclassified
Contestable metering support roles	Includes metering coordinator, metering data provider and metering provider for meters installed or replaced after 1 December 2017.	N/A	Unclassified