



Framework and approach

**Power and Water Corporation
(NT)**

**Regulatory control period
commencing 1 July 2019**

July 2017

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Shortened forms

Shortened Form	Extended Form
Allowance Mechanism	demand management innovation allowance mechanism
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CESS	capital expenditure sharing scheme
CPI	consumer price index
current regulatory control period	1 July 2014 to 30 June 2019
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
F&A	Framework and approach
kWh	kilowatt hours
NEM	National Electricity Market
NEO	National Electricity Objective
NER or the rules	National Electricity Rules As in force in the Northern Territory
next regulatory control period	1 July 2019 to 30 June 2024
opex	operating expenditure
RAB	regulatory asset base
STPIS	service target performance incentive scheme

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).

Power and Water Corporation (PWC) operates the sole monopoly electricity transmission and distribution network in the Northern Territory (NT). The network comprises the poles, wires and transformers used for transporting electricity across urban and rural population centres to homes and business. PWC designs, constructs, operates and maintains the electricity network for electricity consumers in the Northern Territory.

We will make regulatory decisions on the revenue that PWC can recover from its customers. We determine its revenue by an assessment of its efficient costs and forecasts. Our assessment is based on regulatory proposals submitted by the network business in advance of a five year regulatory control period, in this case beginning 1 July 2019. The regulatory proposal sets out PWC's view on its expected costs, services, incentive schemes and required revenues. Our regulatory determination sets out our decisions on these issues. Our decisions on these issues will be made pursuant to the National Electricity Rules (Northern Territory). Therefore, references to the NER in our documents for PWC, including this Framework and Approach (F&A), refer to the NER as in force in the Northern Territory.¹

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. The network business is then provided with incentives to outperform the revenue we determine. The network business retains any savings for a period of time before those savings are passed to customers through lower network bills.

The F&A is the first step in a two year process to determine efficient prices for electricity distribution services in the Northern Territory. 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.

The responsibility for Northern Territory electricity network regulation was transferred to the AER on 1 July 2015.² The 2019–24 regulatory control period will be our first determination for PWC's network. Accordingly, this is the first F&A for PWC under the NER. PWC operates both electricity distribution and transmission assets in the Northern Territory. Ordinarily this would require separate distribution and transmission determinations,

¹ See: [http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/National-Electricity-Rules-\(Northern-Territory\)](http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/National-Electricity-Rules-(Northern-Territory)).

² As part of the NT Government's Electricity Market Reform.

notwithstanding that a single operator provides both types of network services.³ However, in this case, electricity transmission assets operated by PWC have been deemed by the Northern Territory Government to be treated as distribution assets for the purposes of economic regulation.⁴ We will therefore make a single distribution determination for PWC as the operator of distribution and transmission assets in the Northern Territory.

Before reaching our proposed approach, we published a preliminary F&A for PWC on 10 March 2017, seeking submissions from interested parties. Submissions closed on 21 April 2017, with one response received from PWC.⁵

Table 1 summarises the PWC determination process.

Table 1 PWC distribution determination process

Step	Date
AER published preliminary position F&A for PWC	10 March 2017
AER to publish final F&A for PWC	By 1 August 2017
PWC to submit regulatory proposal to AER	31 January 2018
AER to publish Issues paper and host public forum	March/April 2018*
Submission on regulatory proposal close	May 2018
AER to publish draft decision	September 2018
AER to hold a predetermination conference	October 2018
PWC to submit revised regulatory proposal to AER	December 2018
Submissions on revised regulatory proposal and draft decision close	January 2019*
AER to publish PWC determination for regulatory control period	April 2019

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

Source: NT NER, chapter 6.

This overview sets out our positions on:

- classification of distribution services (which services we will regulate)

³ TasNetworks and AusNet Services in Victoria are examples of a single operator of distribution and transmission networks, for which we make two separate determinations, one distribution determination and one transmission determination..

⁴ Section 9 [Declaration of local distribution systems] of the *National Electricity (Northern Territory)(National Uniform Legislation) Act*, July 2016.

⁵ PowerWater, *Submission on AER preliminary framework and approach for NT Power and Water Corporation*, April 2017. See <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/power-and-water-corporation-determination-2019-24/aer-position>.

- control mechanisms (how we will determine prices for regulated services)
- incentives schemes for service quality, capital expenditure, operating expenditure and demand management
- expenditure forecasting tools to test PWC's regulatory proposal
- how we will calculate depreciation of PWC's regulatory asset base.

We summarise below our 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 PWC. Service classification determines what and how service will be regulated. We will regulate services provided on a monopoly basis under a price or revenue cap, which directly controls the charges that a distributor may levy a customer. Less prescriptive regulation is applied where prospect of competition exists. In some situations we may remove regulation altogether. We refer to these as 'unregulated distribution services'. Table 2 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 only by the local distributor.	We set service specific prices to provide a reasonable opportunity to enable the distributor to recover the efficient cost of each service from customers using that service.
Negotiated service		Services we consider require a less prescriptive regulatory approach because all relevant parties have sufficient countervailing market power to negotiate the provision of those services.	Distributors and customers are able to negotiate service and price according to a framework established by the NER. We are available to arbitrate if necessary.
Unclassified distribution		Distribution services that are contestable	We have no role in regulating these

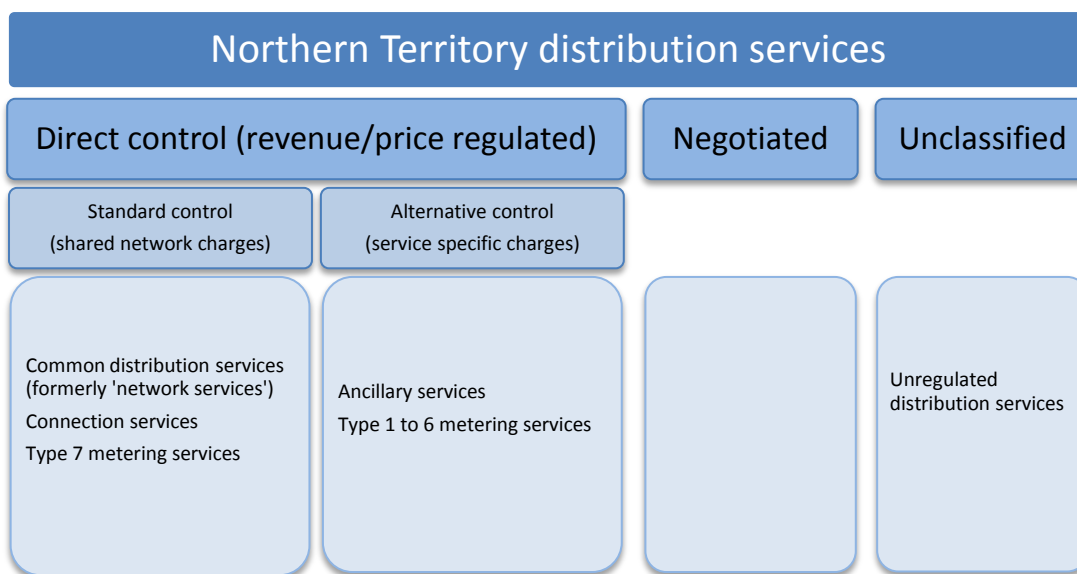
services	will not be classified.	services.
Non-distribution services	Services that are not distribution services. ⁶	We have no role in regulating these services.

Source: AER

Our proposed position is to change the classification of some NT 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 and create consistency and predictability across jurisdictions as far as practicable in how new distribution services might be classified.

Our proposed service classifications for PWC are set out in figure 1 below.

Figure 1 AER proposed classification of PWC distribution services



Source: AER

Our final F&A decision on service classification is not binding for our determination on PWC's regulatory proposal. However, under the NER we may only change our classification approach if unforeseen circumstances arise, justifying a departure from our final F&A position.⁷

Control mechanisms

Following on from service classification, our determination imposes controls on direct control service prices and/or their revenues.⁸ We may only accept or approve control mechanisms

⁶ The NER defines a distribution service as a service provided by means of, or in connection with, a distribution system.

NER, Chapter 10, glossary.

⁷ NER, cl. 6.12.3(b).

⁸ NER, cl. 6.2.5(a).

in a distributor's regulatory proposal if they are consistent with our final F&A.⁹ In deciding control mechanism forms, we must select one or more from those listed in the NER.¹⁰ 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 decision on the form of control mechanisms for PWC is:

- 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.¹¹

Our final F&A decision on the form of control is binding on us and PWC for the 2019–24 regulatory determination.¹² We may only vary our proposed control mechanism formulas in response to unforeseen circumstances.¹³

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 proposed position is to apply the following incentive schemes to PWC:

- Efficiency Benefit Sharing Scheme (EBSS)
- Capital Expenditure Sharing Scheme (CESS)
- Demand Management Incentive Scheme (DMIS) and Innovation Allowance Mechanism (Allowance Mechanism).

We are not proposing to apply the Service Target Performance Incentive Scheme (STPIS) to PWC for the 2019–24 regulatory control period due to the unavailability of reliable historic supply interruption data.

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

Application of our Expenditure Forecast Assessment Guideline

Our Expenditure Forecast Assessment Guideline¹⁴ is based on a reporting framework allowing us to compare the relative efficiencies of distributors. Our proposed position is to

⁹ NER, cl. 6.12.3(c).

¹⁰ NER, cl. 6.2.5(b).

¹¹ 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.

¹² NER, cl. 6.8.1(b)(1)(i).

¹³ NER, cl. 6.12.3(c1).

¹⁴ AER, *Expenditure Forecast Assessment Guideline for Distribution*, November 2013.

apply the guideline, including its information requirements, to PWC in the 2019–24 regulatory control period.

Our expenditure assessment guideline outlines a suite of assessment/analytical tools and techniques to assist our review of PWC’s regulatory proposal. 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 PWC’s regulatory asset base (RAB) for the 2019–24 regulatory control period we must adjust for depreciation. Our proposed approach is to use depreciation based on forecast capex (or forecast depreciation) to establish the opening RAB as at 1 July 2024. In combination with our proposed application of the CESS this approach will maintain incentives for PWC to pursue capital expenditure 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.

All of PWC's high voltage transmission assets are deemed to be part of its distribution system.¹⁵

¹⁵ *National Electricity (Northern Territory)(National Uniform Legislation) Act*. Section 9 and Schedule 2 – Declaration of local distribution systems. This includes PWC's Darwin to Katherine 132kV power line.

1 Classification of distribution services

This chapter sets out our proposed approach on the classification of distribution services provided by PWC for 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,¹⁶ we may classify services so that we:

- directly control prices of some distribution services¹⁷
- allow parties to negotiate services and prices and only arbitrate disputes if necessary, or
- do not regulate some distribution services at all.

This is the first time we have considered PWC's service classification following the transition from jurisdictional regulation of PWC under the Network Access Code as administered by the NT Utilities Commission.¹⁸ Our classification decisions determine which services we will regulate and how PWC will recover the cost of providing those regulated services.

We note 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.¹⁹ While the AEMC's consideration of these rule change requests is ongoing, we have developed our proposed 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. PWC supported this approach where it simplifies the service classification process.²⁰

PWC also noted that the regulatory framework in the Northern Territory is undergoing significant change, which may have unforeseen impacts on our proposed service classifications.²¹ This includes, but is not limited to:

- the NER (NT) being introduced in a series of tranches between 1 July 2016 and 1 July 2019. This means there may be further changes to the NER (NT) after we publish this final F&A.

¹⁶ Reference to the NER means the National Electricity Rules as in force in the Northern Territory, Version 6. See: [http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/National-Electricity-Rules-\(Northern-Territory\)](http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/National-Electricity-Rules-(Northern-Territory)).

¹⁷ 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.

¹⁸ See: <http://www.utilicom.nt.gov.au/Electricity/conduct/Pages/default.aspx>.

¹⁹ 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.

²⁰ PWC, *Letter to AER re: proposed classification table for final F&A for consultation*, May 2017, p. 1.

²¹ PWC, *Letter to AER re: proposed classification table for final F&A for consultation*, May 2017, pp. 1–2.

1.2 AER's assessment approach

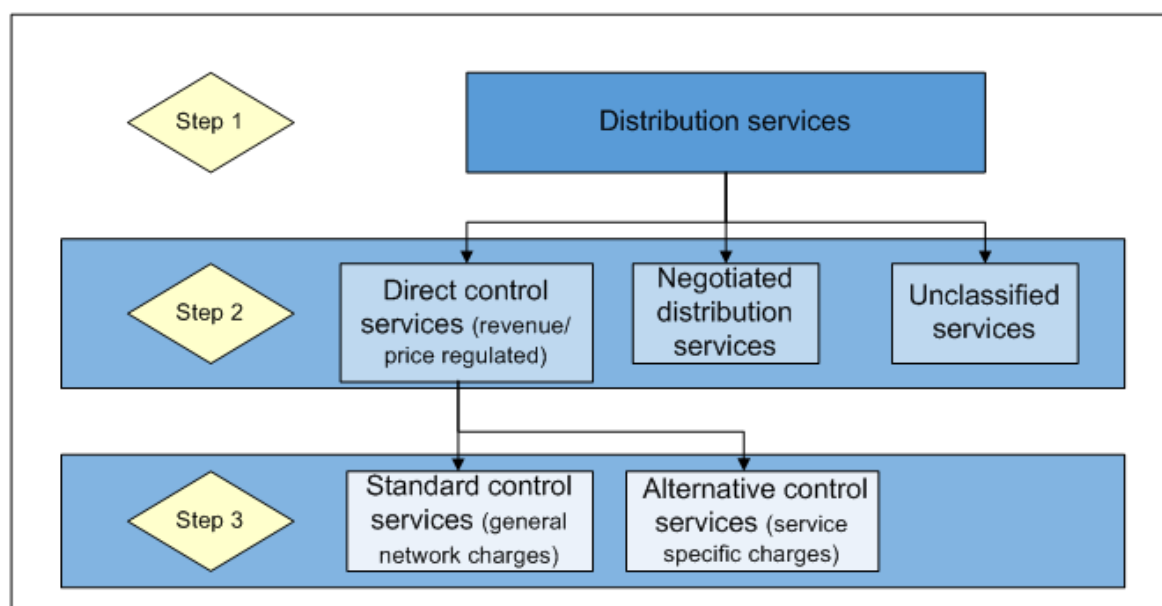
In conducting our assessment of distribution service classification, we commence on the basis that we:

- 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 groups²² – 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 classification 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 distribution service for that regulatory control period. New distribution services (that are created within a regulatory control period) are also to be treated as unregulated distribution services for the remainder of that regulatory control period. 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.

²² NER, cl. 6.2.1(b).

Figure 1.2 Distribution service classification process



Source: NER, chapter 6.

As illustrated by figure 1.2:

- We must first satisfy ourselves that a service is a 'distribution service' (step 1). The NER define a distribution service as a service provided by means of, or in connection with, a distribution system.²³ 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'.²⁴
- 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.²⁵ 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 of regulation applied to services and the desirability of consistency in the form of regulation for similar services both within and beyond the jurisdiction.²⁶

²³ NER, chapter 10, glossary.

²⁴ NER, chapter 10, glossary.

²⁵ NER, cl. 6.2.1(c); NEL, s. 2F.

²⁶ NER, cl. 6.2.1(c).

For services we intend to classify as direct control services, the NER requires us to have regard to a further range of factors.²⁷ 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 directly 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:²⁸

- 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.²⁹

Our classification decisions determine how distributors will recover the cost of providing services.³⁰ 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 who requests 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 efficient 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.
- 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

²⁷ NER, cl. 6.2.2(c).

²⁸ NER, cl. 6.2.2(d).

²⁹ NER, cll. 6.2.1(d) and 6.2.2(d).

³⁰ 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).

distribution 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.³¹

The following points are to assist stakeholders understand the change in classification terminology from the NT Utilities Commission determination³² to our preliminary F&A made pursuant to the NER:

- A regulated network access service is equivalent to a direct control, standard control service classification under the NER.
- An excluded network access service not subject to effective competition is equivalent to a direct control, alternative control service classification under the NER.
- An excluded network access service subject to effective competition is equivalent to the service not being classified under the NER and therefore not subject to regulation by us.

1.3 Reasons for AER's proposed position

This section sets out our proposed service classification and reasons for PWC's 2019–24 regulatory control period for:

- common distribution services
- ancillary services
- metering services
- connection services
- unregulated distribution services.

Appendix B contains a detailed table of our proposed classification of PWC's distribution services for the 2019–24 regulatory control period.

Appendix C includes a table submitted by PWC mapping out its preferred service groupings and classifications.

1.3.1 Common distribution services

This service group was formerly called 'network services'.³³ However, to avoid confusion with the defined terms in chapter 10 of the NER, we propose to rename this service group 'common distribution services'.

³¹ AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

³² Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February 2017, Appendix A at p. 160. See: <http://www.utilicom.nt.gov.au/PMS/Publications/US-FD-NPD14-A.pdf>.

³³ Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February

Common distribution services are concerned with providing a safe and reliable electricity supply to customers.³⁴ Currently in the Northern Territory, these services are classified as standard control services.³⁵ Common distribution services are intrinsically tied to the network infrastructure and the systems that support the shared use of the distribution network by customers. Customers use or rely on access to common distribution services on 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.

We had proposed a description of common distribution services in our preliminary F&A for PWC. Following consideration of submissions, we have adopted the description of common distribution services as proposed by Ausgrid as it more appropriately captures the scope of those services. That description is contained in appendix B. We propose to apply this definition to all distributors, including PWC.

Ausgrid explained that its common distribution services description contains three key parts.³⁶ In short, Ausgrid submitted these are:

1. An overarching description of the services which is based on the definition of 'distribution use of system service' in chapter 10 of the NER. This provides a legally sound footing on which to base the description which is consistent with regulatory obligations as a distributor.
2. A list of the key inputs that are directly or indirectly involved in providing common distribution services. The description only includes the core set of activities which fall into the service group. The exceptions are those activities that fall within common distribution services, but which may not readily appear to do so. For example, activities involved in the relocation of assets forming part of the distribution network but which are not relocations requested by a third party, works to fix damage to the network (including emergency recoverable works) and network demand management for distributor purposes. The phrase 'for distributor purposes' is intended to avoid the capture of unregulated battery storage or micro-grid businesses which provide services that are not distribution services.
3. An express exclusion of any other services that are separately classified but which may still meet the description of common distribution services. The purpose of the exclusion is to ensure that distribution services that are unclassified and therefore unregulated are not inadvertently captured by common distribution services. This is important to facilitate compliance with the ring-fencing guideline.

2017, p. 24.

³⁴ NER, Chapter 10 glossary.

³⁵ Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February 2017, p. 163.

³⁶ Ausgrid, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, pp. 4–5.

Ausgrid submitted that the substance of its amended description varies little from our preliminary F&A description, but provided better accuracy and less ambiguity.³⁷

Our proposed approach is to classify common distribution services as direct control services. PWC holds an electricity distribution licence which is the only distribution license in place for the Northern Territory.³⁸ Under section 17 of the *Electricity Reform Act* (NT) 2000, a person may only distribute electricity if they hold a licence authorising them to do so. These arrangements create a regulatory barrier, preventing third parties from providing common distribution services.³⁹ 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.⁴⁰ Our proposed position is to retain the current standard control classification for common distribution services.⁴¹ There is no potential to develop competition in the market for common distribution services because of the barriers outlined above.⁴² There would be no material effect on administrative costs for us, PWC, users or potential users by continuing this classification.⁴³ We currently classify common distribution services (or 'network services') in all other NEM jurisdictions as standard control services.⁴⁴ Further, distributors provide common distribution services through a shared network and therefore cannot directly attribute the costs of these services to individual customers.⁴⁵

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, our preliminary position was to not classify this service, treating it as an unregulated distribution service. This is because the cost of these works may be recovered through other avenue (e.g. 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. 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 proposed position is for emergency recoverable works to be subsumed into the common distribution services group and classified as a direct control and standard

³⁷ Ausgrid, *Submission on AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, pp. 4–5.

³⁸ Licences are issued by NT Utilities Commission.

³⁹ NER, cl. 6.2.1(c)(1); NEL, ss. 2F(a), (d) and (f).

⁴⁰ NER, cl. 6.2.2(a).

⁴¹ NER, cl. 6.2.2(c)(3) and (4).

⁴² NER, cl. 6.2.2(c)(1).

⁴³ NER, cl. 6.2.2(c)(2), (3).

⁴⁴ NER, cl. 6.2.2(c)(4).

⁴⁵ NER, cl. 6.2.2(c)(5).

control service. PWC supported this approach.⁴⁶ 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. 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 against the efficient operating expenditure (opex) incurred by a distributor in performing emergency recoverable works.⁴⁷ 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.

Our proposed position is a departure from the Utilities Commission's decision to classify emergency recoverable work as a direct control⁴⁸ and alternative control service.⁴⁹ However, our proposed approach results in a consistent treatment of emergency recoverable works across NEM jurisdictions and still provides PWC with a reasonable opportunity to recover these costs where the responsible third party cannot be identified.

1.3.2 Metering services

All electricity customers have a meter that measures the amount of electricity they use. Since publishing our preliminary F&A on 10 March, the AEMC has released chapter 7A of the NER (NT) that provides for PWC to be the monopoly provider of type 1 to 7 metering services⁵⁰ in the NT for the 2019–24 regulatory control period. Consequently, economic regulation will be necessary and we have classified type 1-6 metering services in the NT as alternative control services and type 7 metering services as standard control services. This is further discussed below.

This regulation of metering services differs to the new arrangements that are to commence on 1 December 2017 in other NEM jurisdictions. These arrangements follow on from the AEMC's 26 November 2015 rule change that will open up competition in metering services and give consumers more opportunities to access a wider range of metering services.⁵¹

Type 1 to 6 metering services

Type 1 to 4 meters provide a range of additional functions compared to other meters. In particular, these meter types have a remote communication ability. In the NT, standard type 1 to 4 meters are currently classified as regulated network access services, which is equivalent to standard control services. This is because PWC is currently the monopoly provider of type 1 to 4 meters in the NT. This contrasts to most other NEM jurisdictions

⁴⁶ PWC, *Letter to AER re: proposed classification table for final F&A for consultation*, May 2017, p. 3, line 1 of attachment.

⁴⁷ In our preliminary F&A (at p. 21), we incorrectly stated that the cost of emergency repairs recovered from a third party would be netted off the regulatory asset base and treated like a capital contribution. We have changed our position because our preliminary approach may not have achieved the objective of avoiding over-recovery of costs.

⁴⁸ NER, cl. 6.2.1(d)(1). We have retained a direct control classification.

⁴⁹ Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February 2017, p. 163; NER, cl. 6.2.2(c)(3) and (4).

⁵⁰ We note that type 5 meters are currently not approved for use in the NT.

⁵¹ AEMC, *Competition in metering services information sheet*, 26 November 2015.

where they are competitively available⁵² and hence, unclassified. Similarly, PWC is currently the monopoly provider of type 6 (accumulation) meters, used by small customers and households.

Our proposed position is to classify type 1 to 6 metering services as direct control services and further as alternative control services. Our proposed classification of type 1 to 6 metering services encompasses services like:

- meter provision, installation and maintenance
- meter reading services, including standard and special meter reading and testing
- meter data services.

It also encompasses PWC performing the roles of metering coordinator, metering provider and metering data provider. While we consider a metering coordinator, metering provider or metering data provider are distribution services, our proposed approach in other NEM jurisdictions is to not classify these services.⁵³ That is, we are treating them as unregulated distribution services. However, chapter 7A of the NER stipulates that PWC will perform these roles exclusively for the 2019-24 regulatory control period.

Our reasons for our proposed alternative control classification follow.

PWC, under the NER, has been mandated the monopoly provider of type 1 to 6 metering services until 30 June 2024. This arrangement creates a regulatory barrier, preventing third parties from providing metering services.⁵⁴ Therefore, we consider that there is no opportunity for third parties to enter the market for the provision of metering services in the next regulatory control period.

We must further classify direct control services as either standard or alternative control services.⁵⁵ Unbundling type 1 to 6 metering services from standard control services and classifying them as alternative control services will make our classification consistent with the AEMC's Power of Choice Review. The AEMC's recommendations included:⁵⁶

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

We consider that the AEMC's recommendations provide a basis to move away from the current standard control service classification.⁵⁷ Further,

- While there is not any prospect for competition in metering services for the 2019–24 regulatory control period, a competitive framework does otherwise exist across the NEM. An alternative control service classification will provide customers with transparency

⁵² NER, cl. 7.2.3(a)(2) and 7.3.1.A(a).

⁵³ NER, chapter 10, glossary; *Ergon Energy Corporation Ltd v Australian Energy Regulator* [2012] FCA 393

⁵⁴ NER, cl. 6.2.1(c)(1); NEL, ss. 2F(a), (d) and (f).

⁵⁵ NER, cl. 6.2.2(a).

⁵⁶ AEMC, *Consultation paper — National electricity amendment (expanding competition in metering and related services)*, April 2014.

⁵⁷ NER, cl. 6.2.2(c)(3).

around the pricing of metering services provided by PWC and, if competition is introduced in the future, would provide a price signal on whether to switch to an alternative meter type or metering provider in the future. There may be an immaterial effect on administrative costs to us, PWC, users or potential users by separating metering costs from common distribution services.⁵⁸ However, we consider introducing pricing transparency is in the long term interests of consumers and outweighs any small impact on administrative costs.

- The nature of type 1 to 6 metering services is that the customer requesting the service will benefit from the provision of that service. As such, the costs are directly attributable to identifiable customers.⁵⁹ Our proposed change in service classification protects the broader customer base from incurring additional costs for metering services of no benefit to them.

Therefore our proposed position is to classify type 1 to 6 metering services as alternative control services for the 2019–24 regulatory control period. PWC supported this reclassification.⁶⁰

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. PWC is the monopoly provider of type 7 metering services in the NT⁶¹ and, under the recently adopted chapter 7A of the NER, will remain so for the 2019–24 regulatory control period.

We therefore consider that there is no potential to develop competition in the provision of type 7 metering services.⁶² We intend to classify type 7 metering services as direct control services and further, as standard control services. PWC supported our position.⁶³ This is a continuation of the current classification of type 7 metering services,⁶⁴ and is consistent with the classification of type 7 metering services in other NEM jurisdictions.⁶⁵

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

⁵⁸ NER, cl. 6.2.2(c)(2).

⁵⁹ NER, cl. 6.2.2(c)(5).

⁶⁰ PowerWater, *Submission on AER preliminary framework and approach for NT Power and Water Corporation*, April 2017, p. 6.

⁶¹ Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February 2017, p. 163.

⁶² NER, 6.2.2(c)(1).

⁶³ PowerWater, *Submission on AER preliminary framework and approach for NT Power and Water Corporation*, April 2017, p. 6.

⁶⁴ Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February 2017, p. 163.

⁶⁵ NER, cll. 6.2.1(c)(3) and 6.2.2(c)(4).

1.3.3 Connection services

Put simply, a connection service refers to the services a distributor 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).

PWC's connection services as described above are currently classified as direct control and further, as standard control services.⁶⁶ Our proposed approach is to continue this classification.

PWC holds the only electricity distribution licence to provide connection services in the NT. This licensing arrangement results in a regulatory barrier preventing third parties from providing connection services.⁶⁷ Additionally, we consider the scale and scope of resources available to PWC also prevent the competitive provision of connection services by a third party. We therefore consider that PWC possesses significant market power in the provision of connection services.⁶⁸ For these reasons, we consider that classifying connection services as direct control services is the most appropriate outcome.

Although we classify separate components of connection services⁶⁹ in some other NEM jurisdictions, we do not consider it the most appropriate approach for the NT. This is because PWC may recover costs through shared network charges to the extent that costs have not been recovered as capital contributions under Chapter 5A of the NER.⁷⁰

The purpose of Chapter 5A and the Guideline is to provide a framework and charging principles for new connections or connection alterations.⁷¹ We are mindful of classifying PWC's connection services in a way that supports the operation of Chapter 5A and the Guideline. PWC is required to identify any unique circumstances in its Connection Policy that will form part of its regulatory proposal.⁷²

Under Chapter 5A and the Guideline, connection services classified as standard control services will be charged according to our decision on the form of control (which is a revenue cap in the NT). Chapter 5A and the Guideline also provide that for standard control services a distributor may seek a capital contribution from the customer toward the cost of the

⁶⁶ Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February 2017, p. 24.

⁶⁷ NEL, s. 2F(a).

⁶⁸ NEL, s. 2F(d).

⁶⁹ NER, chapter 5A.

⁷⁰ As permitted by NER, cll. 6.2.1(c)(4) and 6.2.2(c)(6); AER, *Connection charge guidelines for electricity retail customers, under Chapter 5A of the National Electricity Rules*, June 2012.

⁷¹ AER, *Connection charge guidelines for electricity retail customers, under Chapter 5A of the National Electricity Rules*, June 2012, p. 29.

⁷² PWC is yet to submit its Connection Policy. Consequently, the classifications may be inconsistent with the Connection Policy. We will consider any such adjustments in our draft determination to avoid any inconsistencies).

connection service. PWC may only seek a capital contribution from a customer when the incremental cost of the standard control connection service exceeds the estimated incremental revenue expected to be derived from the standard control connection service. Put simply, PWC provides a basic connection to anyone requesting to connect to the network to use electricity. Connections over and above the cost of a basic connection may trigger a capital contribution. This additional charge (capital contribution) may be negotiated between the distributor and the customer.⁷³ The negotiated capital contribution does not alter the classification of the service from standard control to a negotiated distribution service.

This approach avoids the broader customer base bearing the cost of customer specific service requests or where the connection exceeds the cost of a basic connection.

With the effect of Chapter 5A and the Guideline in mind, we intend to retain the current classification of connection services as standard control services.⁷⁴ We consider that there is no basis to move away from this classification as:

- There is little, if any, prospect for competition in the market for connection services.⁷⁵ That is, we are not aware of any NT Government initiatives to introduce contestability for connection services in the 2019–24 regulatory control period. Therefore, our classification will not influence the potential for competition.
- There would be no material effect on administrative costs to us, PWC, users or potential users. This is because classifying connection services as standard control services is consistent with the current regulatory approach.
- We currently regulate connection services in most other NEM jurisdictions under a direct form of control.⁷⁶ We do not regulate some New South Wales connection services, which are competitively available.
- The nature of basic connection services is that in most instances, the customer requesting the service will benefit from the provision of that service. As such, the costs are directly attributable to identifiable customers.⁷⁷ However, application of our Connection Charge Guideline⁷⁸ provides a safety net for the broader customer base. That is, the requirement of the requesting customer to make a capital contribution to a service protects the broader customer base from incurring additional costs for services of no benefit to them.
- We classify standard connection services in Queensland and South Australia as standard control services.⁷⁹ In Victoria and Tasmania, we classify standard connection services as alternative control services.⁸⁰

⁷³ AER, *Connection charge guidelines for electricity retail customers, under Chapter 5A of the National Electricity Rules*, June 2012 and NER, chapter 5A.

⁷⁴ NER, cl. 6.2.2(c)(3).

⁷⁵ NER, cl. 6.2.2(c)(1).

⁷⁶ NER, cl. 6.2.2(c)(4).

⁷⁷ NER, cl. 6.2.2(c)(5).

⁷⁸ AER, *Connection charge guidelines for electricity retail customers, under Chapter 5A of the National Electricity Rules*, June 2012.

⁷⁹ AER, *Final decision, Queensland distribution determination 2015–20*, October 2015, p. 13-19; AER, *Final decision, South*

We must act on the basis that there should be no departure from a previous classification unless another classification is clearly more appropriate.⁸¹ We consider the current standard control classification supports the operation of Chapter 5A and the Guideline and provides a framework for consumers to understand where additional contributions may be required. For these reasons, we intend to classify connection services including premises connections, extensions and network augmentation, as standard control services.

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. relocating poles or temporary supply at a customer's request.). Ancillary services involve work on, or in relation to, parts of PWC's distribution network. Therefore, similar to common distribution services in that only PWC may perform these services in its distribution area.

The above factors create a regulatory barrier preventing any party other than PWC providing ancillary services in its distribution area.⁸² Because of this monopoly position, customers have limited negotiating power in determining the price and other terms and conditions on which PWC provides these services. These factors contribute to the view that PWC possesses significant market power in providing ancillary services.⁸³

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 PWC provides these services to specific customers.⁸⁴ As such, the cost of each ancillary service is directly attributable to an individual customer.⁸⁵ This results in cost transparency for customers and removes cross-subsidisation.

We also consider that there would be no material effect on the administrative costs to us, PWC, users or potential users.⁸⁶ This is because classifying ancillary services as alternative control services is consistent with the current approach.⁸⁷

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 PWC to compete as a discrete price for the service is set for each ancillary service.

⁸⁰ *Australia distribution determination 2015–20*, October 2015, p. 13-15
AER, *Final decision, Victorian DNSPs distribution determination 2016–20*, May 2016, p. 13-20; AER, *Draft decision, TasNetworks distribution determination 2017–19*, p. 13-13.

⁸¹ NER, cl. 6.2.2(d).

⁸² NEL, s. 2F(a).

⁸³ NEL, s. 2F.

⁸⁴ NER, cl. 6.2.2(c)(5).

⁸⁵ NER, cl. 6.2.2(c)(5) – this includes a small number of identifiable customers.

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

⁸⁷ Utilities Commission (NT), *2014 Network Price Determination, Final determination, Part A Statement of reasons*, February 2017, pp. 160–165.

1.3.5 Unregulated distribution services

Unregulated distribution services is the term we use to describe distribution services which we have not classified as either direct control or negotiated services.⁸⁸ 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.⁸⁹ 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.⁹⁰ Under our ring-fencing guideline, any unregulated distribution service would be provided by a separate affiliate. This removes the potential risk of a distributor benefitting from its privileged access to network information to gain a competitive advantage.

The Ring-Fencing Guideline has limited application to PWC from 1 July 2019.⁹¹ Consequently, PWC has a limited set of obligations to meet. PWC is exempt from legal separation, office and staff sharing and branding and promotion obligations. However, PWC is required to comply with obligations dealing with:

- establishing and maintaining accounts
- not discriminating
- information access and disclosure
- conduct of service providers
- compliance and enforcement.⁹²

Therefore, we encourage PWC to continue reviewing what unregulated distribution services it might provide.

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 final 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.⁹³

⁸⁸ AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, p. 13.

⁸⁹ AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

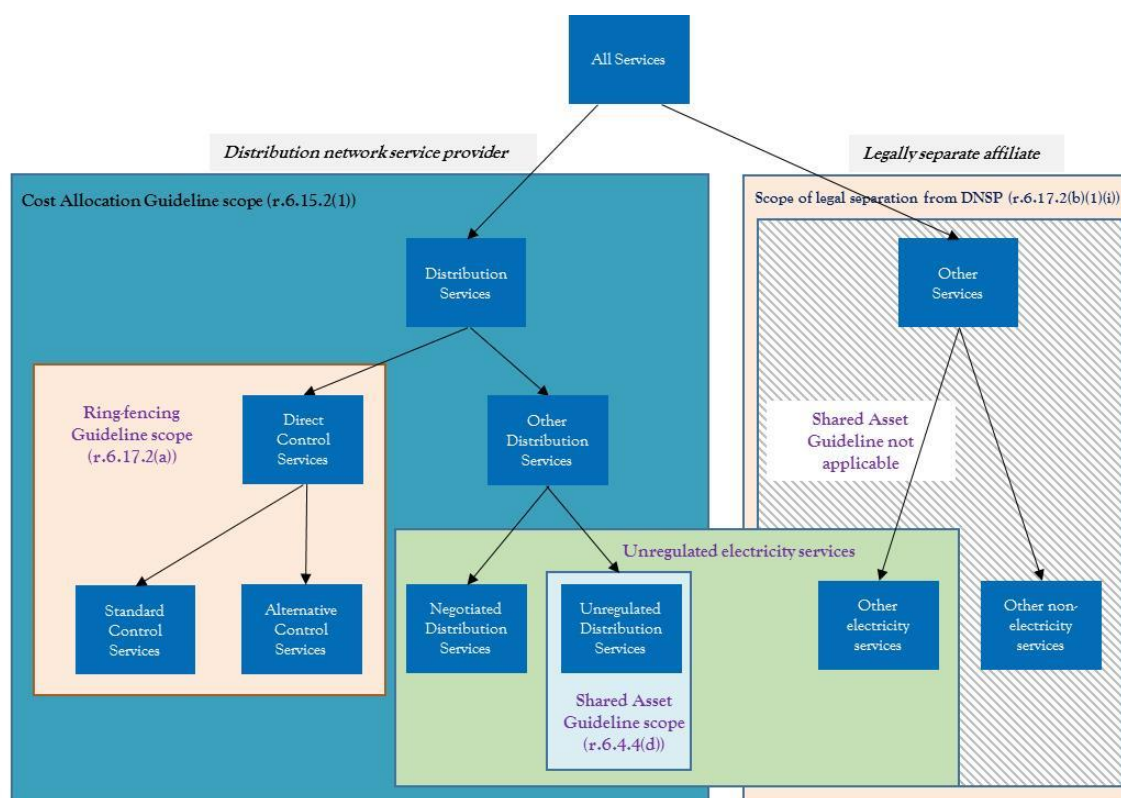
⁹⁰ AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, pp. 13–16.

⁹¹ NER, cl. 6.17.1A and 6.17.1B.

⁹² NER, cl. 6.17.1B.

⁹³ 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) are considering 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. 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.

Distributors, when considering what unregulated distribution services they offer, should refer to the examples contained in the explanatory statement to the ring-fencing guideline⁹⁴ 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

⁹⁴ AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, Appendices A and B, pp. 77–86.

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'.

2 Control mechanisms

Our distribution determination must impose controls over the prices (and/or revenues) of direct control services.⁹⁵ This chapter sets out our decision, together with our reasons on the form of control mechanisms to apply to PWC's direct control services for the 2019–24 regulatory control period. This chapter also sets out our proposed 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 proposed classification of PWC's distribution services.

The form of control mechanisms in a distributor's regulatory proposal must be as set out in the relevant F&A paper.⁹⁶ 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.⁹⁷

2.1 AER's decision

Our decision is to apply the following control mechanisms in the 2019–24 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.

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 mechanisms⁹⁸
- the formulae to give effect to the control mechanisms
- the basis of the control mechanisms.⁹⁹

The NER sets out the control mechanisms that may apply to both standard and alternative control services:¹⁰⁰

- a schedule of fixed prices

⁹⁵ NER, cl. 6.2.5(a).

⁹⁶ NER, cl. 6.12.3(c).

⁹⁷ NER, cl. 6.12.3(c1).

⁹⁸ NER, cl. 6.2.5(b).

⁹⁹ NER, cl. 6.2.6(a).

¹⁰⁰ NER, cl. 6.2.5(b).

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)¹⁰¹

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

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

A revenue cap sets 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 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 ceiling 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 decision on the control mechanisms for PWC's standard control services, we have only considered the continuation of the revenue cap, or adoption of price caps or an

¹⁰¹ 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.

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 which AGL proposed should apply to the standard control services for distributors in other jurisdictions.¹⁰² We did not receive a submission from PWC on this issue.

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.

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.¹⁰³ We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.¹⁰⁴

We have also not considered a hybrid approach as our previous deliberations considered the higher administrative costs outweigh the potential benefits of this form of control.¹⁰⁵

Our decision on the control mechanisms for PWC's alternative control service is based on whether there is reason to depart from a price cap control which is applied to almost all other distributors' alternative control services. Our considerations are against 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 will 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
- the regulatory arrangements in the 2014 NT Network Price Determination¹⁰⁶
- desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)
- any other relevant factor.

¹⁰² AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016.

¹⁰³ 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.

¹⁰⁴ NEL, s. 7.

¹⁰⁵ For example, see: AER, *Final framework and approach for Victorian electricity distributors: Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 86.

¹⁰⁶ Utilities Commission, *2014 Network Price Determination - Part A – Statement of Reasons*, April 2014; Utilities Commission, *2014 Network Price Determination - Part B – Network Price Determination*, April 2014.

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.

The basis of the control mechanism for standard control services must be of the prospective CPI–X form or some incentive-based variant.¹⁰⁷

Section 2.3 sets out our consideration of each of the above factors in deciding on the form of control mechanism for standard control services.

2.2.2 Alternative control services

In determining a control mechanism to apply to alternative control services, we will consider the factors in clause 6.2.5(d) of the 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 of 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 determination¹⁰⁸
- 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 enable 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.¹⁰⁹ 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 or incorporate a pass through mechanism.¹¹⁰

Section 2.4 sets out our consideration of each of the above factors in deciding on the form of control mechanism for alternative control services.

¹⁰⁷ NER, cl. 6.2.6(a).

¹⁰⁸ Utilities Commission, *2014 Network Price Determination - Part A – Statement of Reasons*, April 2014; Utilities Commission, *2014 Network Price Determination - Part B – Network Price Determination*, April 2014.

¹⁰⁹ NER, cl. 6.2.6(b).

¹¹⁰ NER, cl. 6.2.6(c).

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

Our decision is to maintain a revenue cap for PWC's standard control services for the 2019–24 regulatory control period. We have made our decision to apply a revenue cap control mechanism having regard to the factors set out under clause 6.2.5(c) of the NER.

A revenue cap will result in minimal additional administrative costs and allow for consistency of regulatory arrangements for standard control services both across regulatory periods and across jurisdictions.

A revenue cap will also 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 variability 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.¹¹¹ We consider tariff structures are efficient if they reflect the underlying cost of supplying distribution services.

It is likely that efficient tariff structures can be developed and implemented under all types of control mechanisms. 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.

Our previous 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.¹¹² 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 a distributor to prepare a tariff structure statement 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.

¹¹¹ NER, cl. 6.2.5(c)(1).

¹¹² 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.¹¹³ The tariff structure statement should show how a distributor applied the distribution pricing principles¹¹⁴ 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:¹¹⁵

the tariffs that a distributor charges for provision of direct control services to a retail customer should reflect the distributor's 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.¹¹⁶

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. On 28 April 2017, we made our final decision on TasNetworks' initial tariff structure statement.

Through the initial tariff structure statements many distributors will be introducing more cost reflective tariff structures such as demand based tariffs. In our assessment we found no evidence to suggest that ActewAGL's average revenue cap or other distributors' revenue caps inhibited the ability to develop or implement efficient tariff structures. Therefore, we consider that efficient tariff structures 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 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.

¹¹³ NER, cl. 6.18.1A(a)(3).

¹¹⁴ 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).

¹¹⁵ NER, cl. 6.18.5(a).

¹¹⁶ NER, cl. 6.12.3(k).

2.3.2 Administrative costs

In deciding on a control mechanism, the NER require us to have regard to the possible effects of the control mechanism on administrative costs.¹¹⁷ 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 PWC's standard control services would have the least complexity and administrative burden. The continuation of a revenue cap would impose minimal additional administrative costs for us, PWC or users. We consider only minor adjustments are needed in transitioning from PWC's current revenue cap to the revenue cap that is applied to distributors already regulated under the NER. For example, we note our preliminary position revenue cap control formula as set out in Figure 2.1 is not dissimilar to that applied to PWC currently.¹¹⁸

In contrast, more substantial administrative costs will be incurred by at least PWC 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 addressing 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.¹¹⁹ For PWC these arrangements are set out by the Utilities Commission in the 2014 NT Network Price Determination. We note maintaining a revenue cap control mechanism for PWC's 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 having regard to 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 the relevant jurisdiction.¹²⁰ We consider maintaining a revenue cap control mechanism for PWC's standard control services delivers consistent regulatory arrangements for these services across jurisdictions.

¹¹⁷ NER, cl. 6.2.5(c)(2).

¹¹⁸ Utilities Commission, *2014 Network Price Determination - Part B – Network Price Determination*, April 2014, Schedules 4 and 5, pp. 51–55.

¹¹⁹ NER, cl. 6.2.5(c)(2A).

¹²⁰ NER, cl. 6.2.5(c)(4).

Apart from ActewAGL, all other electricity distributors' who are currently subject to economic regulation under the NER have a revenue cap control mechanism applied to their standard control services. However, we have decided to apply a revenue cap to ActewAGL's standard control services for the 2019–24 regulatory control period.¹²¹ This means that from 1 July 2019 all distributors' standard control services will be subject to a revenue cap control mechanism. Therefore maintaining a revenue cap control mechanism for PWC will ensure consistent regulatory arrangements for these services across all NEM jurisdictions. For these reasons, we consider the continuation of a revenue cap control mechanism is superior in addressing 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. Also, 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.¹²²

In the concurrent F&A processes, AGL submitted that we review the control on distributors' revenues in light of uncertainty around future network demand and utilisation.¹²³ 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 a revenue cap incentivises distributors to reduce their expenditures 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.

In contrast, 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 gain revenues above efficient cost levels.¹²⁴ A systematic recovery of revenue above efficient cost recovery results in higher bills for consumers.¹²⁵ We

¹²¹ ActewAGL Distribution, *Response to AER preliminary framework and approach*, April 2017, p. 11.

¹²² 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.

¹²³ AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016, p. 2.

¹²⁴ For example, see: AER, *Preliminary positions: Framework and approach paper ActewAGL—Regulatory control period commencing 1 July 2014*, pp. 64–67; AER,

¹²⁵ 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.

consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.¹²⁶

In terms of efficient revenue recovery, we consider a revenue cap control mechanism better reflects the national electricity objective than those that rely on energy sales.¹²⁷

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 retailers' ability to manage risks incurred from changes to network tariffs, which they then package into retail plans for customers. It also affects customers' ability to manage their bills.

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 requires various annual price adjustments regardless of the control mechanism.¹²⁸

Within a regulatory control period, an average revenue cap or price caps will deliver more overall price stability than a revenue cap. The increased variability 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 in its submission to TasNetworks' preliminary F&A, under a revenue cap falling demand creates price increases.¹²⁹ 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.

Typically there is a two year lag from when 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 $t-1$).¹³⁰ The inclusion of this estimated year helps smooth year-on-year revenue and tariff adjustments because the

¹²⁶ NEL, s. 7.

¹²⁷ NEL, s. 7.

¹²⁸ These include cost pass throughs, jurisdictional scheme obligations, tribunal decisions and transmission prices passed on to the distributors from transmission network service providers.

¹²⁹ AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016, p. 2.

¹³⁰ For example, see: AER, *Final Decision, CitiPower distribution determination 2016 to 2020: Attachment 14—Control mechanisms*, May 2016, Appendix A, pp. 18–19.

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 stability across regulatory control periods, we consider an average revenue cap can result in greater price volatility compared to a revenue cap.¹³¹ 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 decision is to maintain a revenue cap control mechanism for PWC's 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 effect.

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.¹³² 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.

As stated above, AGL submitted that a price cap control mechanism be considered in light of uncertainty around network demand and utilisation.¹³³ 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.¹³⁴ 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

¹³¹ AER, *Preliminary positions: Framework and approach paper ActewAGL—Regulatory control period commencing 1 July 2014*, pp. 67–69.

¹³² Generally peak demand is referred to as the maximum load on a section of the network over a very short time period.

¹³³ AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016, p. 2.

¹³⁴ 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.

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 the decline in demand or consumption that they induce.

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.¹³⁵ 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.¹³⁶ Below is proposed formula to apply to PWC's standard control services revenues. We consider that the formula gives effect to the revenue cap.

Figure 2.1 Proposed revenue cap to be applied to PWC's standard control services

1. $TAR_t \geq \sum_{i=1}^n \sum_{j=1}^m p_t^{ij} q_t^{ij}$ i = 1,...,n and j = 1,...,m and t = 1, 2,...,5
2. $TAR_t = AAR_t + I_t + B_t + C_t$ t = 1, 2,...,5
3. $AAR_t = AR_t$ t = 1
4. $AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t)$ t = 2,...,5

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.

¹³⁵ NER, cl. 6.8.1(b)(2)(ii).

¹³⁶ NER, cl. 6.12.3(c1).

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.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities¹³⁷ 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 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

We intend to apply caps on the prices of individual services (price caps) in the 2019-24 regulatory control period to all of PWC's alternative control service.¹³⁸ We have reached this conclusion on the application of price caps for PWC's alternative control services having regard to the factors set out under clause 6.2.5(d) of the NER. We propose classifying the following services as alternative control services:

- type 1 to 6 metering services
- ancillary services.

Unlike standard control services, the NER is not prescriptive on the basis of the control mechanism for alternative control services.¹³⁹ For example, the price caps could be based

¹³⁷ 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.

¹³⁸ The Consumer Challenge Panel supported maintaining price caps for alternative control services. Consumer Challenge Panel - Sub Panel CCP4, *Submission*, 10 March 2015.

¹³⁹ NER, cl. 6.2.6(c).

on a building block approach, or a modified building block cost build up. We have set out our proposed 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 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 proposed 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.

Our consideration of the relevant factors is set out below.

2.4.1 Influence on the potential to develop competition

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

2.4.2 Administrative costs

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

We consider that PWC is likely to incur additional administrative costs in the short run regardless of type of control mechanism as there is currently no control mechanism applied to the PWC services which our F&A classifies as alternative control services.

However, we consider the application of price caps to these services is likely to incur the least amount of additional administrative burden for PWC as the current development for these prices most closely resembles the development of prices under a price cap.¹⁴⁰

2.4.3 Existing regulatory arrangements

In deciding on a control mechanism, the NER requires us to have regard to the existing regulatory arrangements applicable to PWC in the 2014 NT Network Price Determination.¹⁴¹

We note that there is currently no control mechanism applied PWC's alternative control services but rather that clause 72(4) of The Electricity Networks (Third Party Access) Code 2015¹⁴² requires them to be provided on fair and reasonable terms.¹⁴³ If PWC and the

¹⁴⁰ PWC, *Power Networks: 2016–17 Electricity network tariffs and charges and future price trends*, June 2016, p. 8.

¹⁴¹ NER, cl. 6.2.5(d)(2A).

¹⁴² The Electricity Networks (Third Party Access) Code, which is a schedule to the *Electricity Networks (Third Party Access) Act*.

customer cannot reach agreement then we have a role in determining what constitutes fair and reasonable. We consider this type of regulation is a negotiated service.

Under the NER, an alternative control service must be subject to price or revenue control.¹⁴⁴ As such, the negotiation of price for these services cannot continue and this has informed our approach..

2.4.4 Desirability of consistency between regulatory arrangements

We consider consistency across jurisdictions is also generally desirable. Our proposed 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.¹⁴⁵ 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.¹⁴⁶

Below are our proposed positions price cap formulae which will apply to PWC's alternative control services.

Figure 2.2 Price cap formulae to be applied to PWC's type 1–6 metering and ancillary fee based services

$$\bar{p}_t^i \geq p_t^i \quad i=1,\dots,n \text{ and } t=1, 2,\dots,5$$

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

Where:

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

¹⁴³ Utilities Commission, *2014 Network Price Determination - Part A – Statement of Reasons*, April 2014, pp. 25–26.

¹⁴⁴ NER, cl. 6.2.5(a).

¹⁴⁵ NER, cl. 6.8.1(b)(2)(ii).

¹⁴⁶ NER, cl. 6.12.3(c1).

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

\bar{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 Cities¹⁴⁷ 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 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

Figure 2.3 Price cap formula to be applied to PWC's ancillary 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 Cities¹⁴⁸ from the December quarter in year t-2 to the December quarter in year t-1, calculated using the following method:

¹⁴⁷ 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.

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 $t-1$

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 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 proposed application of a range of incentive schemes to the PWC for the next regulatory control period. At a high level, we intend to apply the:

- efficiency benefit sharing scheme
- capital expenditure sharing scheme
- demand management incentive scheme and innovation allowance mechanism.

3.1 Service target performance incentive scheme

This section sets out our reasons for not applying the service target performance incentive scheme (STPIS) to PWC in the next regulatory control period.

Our distribution STPIS¹⁴⁹ provides a financial incentive to distributors to maintain and improve service performance. The scheme aims to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributors' incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the 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 customers¹⁵⁰ experiencing service below a predetermined level. This component only applies if there is not another GSL scheme already in place.¹⁵¹

3.1.1 AER's proposed position

Our proposed position is not to apply the s-factor component of the STPIS to PWC in the next regulatory control period, due to the unavailability of reliable historic supply interruption data. However, we will be collecting relevant data during the course of the 2019–24 regulatory control period in order to establish suitable targets for the following regulatory control period.

¹⁴⁹ AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009.

¹⁵⁰ Except where a jurisdictional electricity GSL requirement applies.

¹⁵¹ 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.

We will also not apply the GSL component if PWC remains subject to a jurisdictional GSL scheme. In the Northern Territory, the Utilities Commission sets out GSLs that apply to PWC.¹⁵² Our intention is to not create duplication or compromise PWC's 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 Northern Territory code remain in place. We will reconsider this position if the Northern Territory Government advises that these arrangements will cease to apply.

PWC supported our proposed approach.¹⁵³

3.2 Efficiency benefit sharing scheme

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

3.2.1 AER's proposed position

We expect to apply the EBSS to PWC in the 2019–24 regulatory period. We will decide if and how we will apply it in our determination. Our determination will take into account the information available to us at that time as to PWC's revealed costs and the basis on which we approve PWC's forecast opex. This will inform our view as to whether the application of the EBSS will result in the fair sharing of efficiencies between consumers and PWC.¹⁵⁴ PWC accepted our proposed approach.¹⁵⁵

3.2.2 AER's assessment approach

The EBSS must provide for a fair sharing of opex efficiency gains and efficiency losses between a distributor and consumers.¹⁵⁶ We must also have regard to the following factors in developing and implementing the EBSS:¹⁵⁷

- 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 distributors with a continuous incentive to reduce opex
- the desirability of both rewarding distributors for efficiency gains and penalising distributors for efficiency losses

¹⁵² Utilities Commission, *Guaranteed Service Level Code*, 1 January 2012.

¹⁵³ PWC, *Submission on AER's preliminary Framework and Approach Paper for Power and Water Corporation's Regulatory Control Period Commencing 1 July 2019*, 21 April, 2017, p. 1.

¹⁵⁴ NER, cl. 6.5.8(a).

¹⁵⁵ PWC, *Submission on the AER's preliminary framework and approach for Power and Water Corporation*, 21 April 2017, p. 5.

¹⁵⁶ NER, cl. 6.5.8(a).

¹⁵⁷ NER, cl. 6.5.8(c).

- any incentives that distributors may have to capitalise expenditure
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

3.2.3 Reasons for AER's proposed position

The EBSS is intrinsically linked to a distributor's revealed costs. In assessing a distributor's opex proposal, we seek to identify an efficient opex amount in the base year (the 'revealed costs' of the distributor), which we use to develop an alternative estimate of total opex for the 2019–23 regulatory control period. We compare this to a distributor's opex proposal when assessing it against the opex criteria. If we approve opex that reflects a distributor's revealed costs and apply the EBSS, and the distributor then makes an incremental efficiency gain, it will receive a reward through the EBSS. The lower revealed costs will inform our assessment of the distributor's proposed opex forecast for the subsequent period such that consumers are likely to benefit from those lower costs on an ongoing basis. This is how efficiency improvements are shared between consumers and the business.

Where approved forecast opex reflects revealed costs, the application of the EBSS serves two important functions:

1. it removes the incentive for a service provider to inflate opex in the expected base year in order to gain a higher opex forecast for the next regulatory control period
2. it provides a continuous incentive for a service provider to pursue efficiency improvements across the regulatory control period.

The EBSS does this by allowing a service provider to retain efficiency gains (or losses) for a total of six years (typically), regardless of the year in which it was made.

We will determine if we will apply the EBSS when we have PWC's proposal and assess that against PWC's revealed costs. This will inform us as to whether the application of the EBSS will sufficiently benefit electricity consumers in terms of any likely reward or penalty, and if it will provide a continuous incentive to PWC to pursue efficiency improvements.

3.3 Capital expenditure sharing scheme

The CESS provides financial rewards for distributors whose capex becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices. This section sets out our proposed approach and reasons for how we intend to apply version 1 (dated 29 November 2013) of the CESS to PWC in the next regulatory control period. The CESS approximates efficiency gains and efficiency losses by calculating the difference between forecast and actual capex. It shares these gains or losses between distributors and network users.

The CESS works as follows:

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

- We calculate the CESS payments taking into account the financing benefit or cost to the distributor of any underspend or overspend amount.¹⁵⁸ We can also make further adjustments to account for deferral of capex and ex post exclusions of capex from the RAB.
- The CESS payments will be added or subtracted to the distributor's regulated revenue as a separate building block in the next regulatory control period.

Under the CESS a distributor retains 30 per cent of 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 proposed position

We intend to apply the CESS, as set out in our capex incentives guideline,¹⁵⁹ to PWC in the 2019–24 regulatory control period. PWC supported our proposal to apply CESS in the next regulatory control period.¹⁶⁰

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:¹⁶¹

- make that decision in a manner that contributes to the capex incentive objective set out in the NER¹⁶²
- consider the CESS principles,¹⁶³ capex objectives,¹⁶⁴ other incentive schemes, and where relevant the opex objectives, as they apply to the particular distributor, and the circumstances of the distributor.

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

3.3.3 Reasons for AER's proposed position

PWC is not currently subject to a CESS. PWC proposed that the CESS should not apply in the next regulatory control period.¹⁶⁵ PWC considered that the CESS (and EBSS) is best applied when the market and supporting regulatory framework are stable and predictable to

¹⁵⁸ 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.

¹⁵⁹ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9.

¹⁶⁰ PWC, *Submission on the AER's preliminary framework and approach for Power and Water Corporation*, 21 April 2017, p.

¹⁶¹ NER, cl. 6.5.8A(e).

¹⁶² NER, cl. 6.4A(a); the capex criteria are set out in cl. 6.5.7(c) of the NER.

¹⁶³ NER, cl. 6.5.8A(c).

¹⁶⁴ NER, cl. 6.5.7(a).

¹⁶⁵ PWC, *Letter to the AER, framework and approach, application of incentive schemes*, February 2017, p. 1.

avoid unexpected and unintended consequences.¹⁶⁶ PWC further stated that their regulatory environment is in a state of flux and the status of regulatory instruments is not expected to be fully known until at least mid-2018.¹⁶⁷ PWC also referred to regulatory precedent, where the EBSS was not applied to Ausgrid in its current regulatory control period.¹⁶⁸ We understand that any uncertainty regarding PWC's regulatory arrangements will be resolved prior to the next regulatory control period such that the application of ex-ante incentives (including the CESS) is likely to contribute to the capex objective. In the context of our Ausgrid decision, as noted by PWC, we decided not to apply the CESS in the current regulatory control period on the basis that the EBSS is intrinsically linked to the 'revealed cost' method of forecasting opex. However, as the method of forecasting capex is not directly linked to the revealed cost approach this issue does not arise in relation to the application of a CESS. Our reasoning for our preliminary position is detailed below.

As part of our Better Regulation program we consulted on and published version 1 of the capex incentives guideline which sets out the CESS.¹⁶⁹ The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.¹⁷⁰ 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 EBSS which PWC may be subject to in the next regulatory control period.

For capex, the sharing of underspend and overspend amounts happens at the end of each regulatory 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.¹⁷¹ Because of this a distributor may choose to spend capex earlier, or on capex when it may otherwise have spent on opex, or less on capex at the expense of service quality—even if it may not be efficient to do so.

With the CESS a distributor faces the same reward and penalty in each year of a regulatory control period for capex underspends or overspends. The CESS will provide distributors with an ex ante incentive to spend only efficient capex. Distributors that make efficiency gains will be rewarded through the CESS. Conversely, distributors that make efficiency losses will be penalised through the CESS. In this way, distributors will be more likely to incur only efficient

¹⁶⁶ PWC, *Letter to the AER, framework and approach, application of incentive schemes*, February 2017, p. 3.

¹⁶⁷ PWC, *Letter to the AER, framework and approach, application of incentive schemes*, February 2017, p. 3.

¹⁶⁸ PWC, *Letter to the AER, framework and approach, application of incentive schemes*, February 2017, p. 4.

¹⁶⁹ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9.

¹⁷⁰ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 10–12.

¹⁷¹ 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 any underspend in the regulatory period, the greater its reward will be.

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.

3.4 Demand management incentive scheme and innovation allowance mechanism

This section sets out our proposed approach and reasons for applying our new demand management incentive scheme (DMIS) and demand management allowance mechanism (Allowance Mechanism) to PWC in the 2019–24 regulatory control period.

On 20 August 2015, the AEMC published a rule determination changing the application of the existing demand management incentive scheme (current scheme) that applied to distributors¹⁷² There are now two parts of the framework under the NER:

- The DMIS, with the objective to provide distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management.
- The Allowance Mechanism, with the objective to provide distributors with funding for research and development in demand management projects that have the potential to reduce long term network costs.

In contrast, the objective under the current scheme has been to provide incentives for distributors 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 respective objectives of the new DMIS and Allowance Mechanism are therefore different to that under the current scheme.

The DMIS and Allowance Mechanism will not affect the classification of distribution services, the form of the control mechanisms as specified in this F&A or the formulas that give effect to those mechanisms.

We are currently developing a new DMIS and Allowance Mechanism. We published a consultation paper in January, facilitated a stakeholder forum in April, and ran a stakeholder videoconference in June.¹⁷³ We expect to publish the new DMIS and Allowance Mechanism by late 2017.

3.4.1 AER's proposed position

We are currently developing the new DMIS and Allowance Mechanism to apply across the NEM, including PWC in the 2019–24 regulatory control period. PWC accepted our preliminary position to apply the new DMIS and Allowance Mechanism in the next regulatory control period.¹⁷⁴

¹⁷² AEMC, *Rule Determination: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, August 2015.

¹⁷³ For details on our consultation process, see our demand management project page under:

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

¹⁷⁴ PowerWater, *Submission on AER preliminary framework and approach for NT Power and Water Corporation*, 21 April

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 PWC.¹⁷⁵ These are:

DMIS Objective

- The DMIS should provide PWC with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management.

Benefits to consumers

- The DMIS should reward PWC 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 proposed position on DMIS

This section outlines the reasons for our intention to apply the DMIS to PWC in the 2019–24 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. In the context of providing

¹⁷⁵ 2017, p. 4.
NER, cl. 6.6.3(c).

distribution services, 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.¹⁷⁶ Demand management that effectively reduces network utilisation during peak usage periods can be an economically efficient way of deferring the need for network augmentation.

DMIS Objective

The DMIS must incentivise distributors to undertake non-network initiatives relating to demand management. Developing such incentives requires considering the impacts of control mechanisms in providing incentives. It also requires considering how a DMIS will promote cost efficient non-network options that relate to and are likely to achieve demand management outcomes. Our consultation paper discussed a range of mechanisms that could contribute to the achievement of this objective.¹⁷⁷

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 net cost savings to retail customers.¹⁷⁸ The NER recognise that these net cost savings to retail customers could be via the net economic benefits delivered from implementing relevant non-network options.¹⁷⁹ We will design the DMIS so its expected long term benefits exceed the costs to consumers resulting from any associated adjustment to regulated revenues. The NER recognise that the operation of the DMIS may result in benefits that accrue over multiple periods.

Balanced incentives

We intend to assess projects, for which distributors apply for incentives under the DMIS, using criteria that will balance the incentives between expenditure on network options and non-network options relating to demand management. We must also design the DMIS so the costs to consumers resulting from the associated adjustment to regulated revenues do not exceed its long term expected benefits, including when we take into account the net economic benefits across all participants in the market. In balancing this, we recognise that the operation of the DMIS may result in cost impacts within a regulatory control period where the benefits are unlikely to be revealed until later periods.

The DMIS will encourage demand management initiatives which are likely to provide long term efficiency gains to energy consumers that will outweigh any short term price increases. For instance, these initiatives might reduce the costs of investment in new infrastructure. This might occur through the deferral of, or removal of the need for, network

¹⁷⁶ 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.

¹⁷⁷ AER, *Consultation Paper- Demand management incentive scheme and innovation allowance mechanism*, January 2017.

¹⁷⁸ NER, cl. 6.6.3(c)(2).

¹⁷⁹ NER, cl. 6.6.3(c)(3).

augmentation/expansion or replacement/refurbishment expenditures, such as via a more efficient use of existing infrastructure.

The DMIS will be designed so all costs recovered from other sources will be excluded from its incentive payments. In developing the DMIS, we are having regard to the effect that it could have on the incentives created by the EBSS, CESS and STPIS, and vice versa. We are also avoiding imposing penalties as part of the DMIS.

3.4.4 AER's assessment approach to the Allowance Mechanism

The NER require us to take several factors into account in developing and implementing an Allowance Mechanism for PWC.¹⁸⁰ These are:

Allowance Mechanism Objective

- The Allowance Mechanism should provide PWC 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 Allowance Mechanism should provide a reasonable level of the allowance considering the long term benefit to retail customers. It should only provide funding that is not available from any another source, including under a relevant distribution determination.
- The Allowance Mechanism 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 proposed position on Allowance Mechanism

This section outlines the reasons for our position to apply the Allowance Mechanism to PWC in the 2019–24 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 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.

¹⁸⁰ NER, cl. 6.6.3A(c).

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

Allowance Mechanism Objective

The Allowance Mechanism objective is 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 Allowance Mechanism design will aim to fund demand management with the potential to reduce long term network costs. It will fund 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 should be willing to remove funding ex-post for projects that fall short of this principle.

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 Allowance Mechanism. For example, clarification of innovative tariff trials may be required.

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

The design of the Allowance Mechanism will require distributors to publish reports on the nature and results of demand management projects that receive the allowance. Publication of such reports enables the knowledge gained from these 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 assessment guideline (the EFA guideline)¹⁸¹ including the information requirements applicable to PWC for the 2019–24 regulatory control period. The EFA guideline sets out our expenditure assessment approach developed and consulted upon during the Better Regulation program. It outlines the assessment techniques we will use to assess a network service provider's proposed expenditure forecasts, and the information we require from the network service provider.

The EFA guideline uses a nationally consistent reporting framework that allows us to compare the relative efficiencies of network service providers and decide on efficient expenditure forecasts. The NER require PWC to advise us by 30 June 2017 of the methodology they propose to use to prepare their forecasts.¹⁸² In the F&A we must advise whether we will deviate from the EFA guideline.¹⁸³ This will provide clarity on how we will apply the EFA guideline and the information PWC should include in its regulatory proposals. This contributes to an open and transparent process and makes our assessment of expenditure forecasts more predictable.¹⁸⁴

The EFA guideline contains a suite of assessment/analytical tools and techniques to assist our review of the expenditure forecasts network service providers include in their regulatory proposals. We intend to have regard to the assessment tools set out in the guideline. The tool kit includes:

- 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.¹⁸⁵

We exercise judgement to determine the extent to which we use a particular technique to assess 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.

PWC did not raise any specific concerns about the application of the EFA guideline.¹⁸⁶

¹⁸¹ We developed the EFA guideline in accordance with clauses 6.4.5 of the NT NER. We published this guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864.

¹⁸² NER, cl. 6.8.1A(b)(1).

¹⁸³ NER, cl. 6.8.1(b)(2)(viii).

¹⁸⁴ As per the requirement NER, cl. 6.8.2(c2) PWC is required to submit expenditure assessment information in their regulatory proposal. PWC's response to Reset Regulatory Information Notice pertaining to the forecast data will satisfy the information requirements contained in the AER's Expenditure Forecast Assessment Guideline as set out in this F&A.

¹⁸⁵ AER, *Explanatory statement: Expenditure assessment guideline for electricity transmission and distribution*, 29 November 2013.

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 proposed approach on the form of depreciation to be used when PWC's RAB is 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.¹⁸⁷ 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

¹⁸⁶ PowerWater, *Submission on AER preliminary framework and approach for NT Power and Water Corporation*, 21 April 2017, p. 1 and p. 5.

¹⁸⁷ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, 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 proposed position

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

5.2 AER's assessment approach

We have to decide for our distribution determination whether we will use actual or forecast depreciation to establish a distributor's RAB at the commencement of the following regulatory control period.¹⁸⁸

We 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.¹⁸⁹ Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:¹⁹⁰

- 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 proposed position

Consistent with our capex incentives guideline, we propose to use the forecast depreciation approach to establish the RAB for PWC at the commencement of the 2024–29 regulatory control period. PWC noted our proposed forecast depreciation approach to establish the opening RAB and did not raise any concerns about this approach.¹⁹¹

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.¹⁹²

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

¹⁸⁸ NER, cl. S6.2.2B.

¹⁸⁹ NER, cl. 6.4A(b)(3).

¹⁹⁰ NER, cl. S6.2.2B.

¹⁹¹ PowerWater, *Submission on AER preliminary framework and approach for NT Power and Water*, April 2017, p. 5.

¹⁹² AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 10–12.

- 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 actual depreciation. This is consistent with the 2014 final determination made by the Utilities Commission of the Northern Territory that applies to PWC for the 2014–19 regulatory control period.¹⁹³ The use of forecast depreciation to establish the opening RAB at the commencement of the 2014–29 regulatory control period will therefore represent a change of approach. PWC is not currently subject to a CESS but we propose to apply the CESS in the 2019–24 regulatory control period. We discuss this further in section 3.3.

For PWC, 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.¹⁹⁴ 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.

¹⁹³ Utilities Commission of the Northern Territory, *2014 Network Price determination, Final determination, Part B–Network price determination*, April 2014, p. 12.

¹⁹⁴ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 13–19 and 20–21.

Appendix A: Rule requirements for classification

We must have regard to four factors when classifying distribution services.¹⁹⁵

- 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.¹⁹⁶
- 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)¹⁹⁷
- the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)¹⁹⁸
- any other relevant factor.¹⁹⁹

The NER specify additional requirements for services we have regulated before.²⁰⁰ They are:

¹⁹⁵ NER, cl. 6.2.1(c).

¹⁹⁶ NEL, s. 2F.

¹⁹⁷ NER, cl. 6.2.1(c)(2).

¹⁹⁸ NER, cl. 6.2.1(c)(3).

¹⁹⁹ NER, cl. 6.2.1(c).

²⁰⁰ NER, cl. 6.2.1(d).

- 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.²⁰¹

- 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.²⁰²

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.

²⁰¹ NER, cl. 6.2.2(c).

²⁰² NER, cl. 6.2.2(c).

Appendix B: Proposed service classification of NT distribution services²⁰³

Service group/Activities included	Further description	Current Classification 2014–19 ²⁰⁴	Proposed classification 2019–24
Common distribution services			
Common distribution services (formerly 'network services')	<p>The suite of services involved in the use of the distribution network for the conveyance of electricity (including the service that ensures the integrity of the related distribution system) and includes but is not limited to the following:</p> <ul style="list-style-type: none"> • the planning, design, repair, maintenance, construction and operation of the distribution network • the relocation of assets that form part of the distribution network but not relocations requested by a third party (including a customer) • works to fix damage to the network (including emergency recoverable works) or to support another distributor during an emergency event • network demand management for distribution purposes • training internal staff and contractors undertaking direct control services 	Standard control	Standard control

²⁰³ The examples and activities listed in the 'Further description' column are not intended to be an exhaustive list and some distributors may not offer all activities listed. Rather the examples provide a sufficient indication of the types of activities captured by the service.

²⁰⁴ Per Utilities Commission (NT), *2014 Network Price Determination, Final determination, (Part A Statement of reasons and Part B Pricing Determination)*, February 2017. See: <http://www.utilicom.nt.gov.au/AboutTheCommission/consultations/2014/Pages/default.aspx>.

Service group/Activities included	Further description	Current Classification 2014–19 ²⁰⁴	Proposed classification 2019–24
	<ul style="list-style-type: none"> activities related to ‘shared asset facilitation’ of distributor assets emergency disconnect for safety reasons and work conducted to determine if a customer outage is related to a network issue bulk supply metering rectification of simple customer fault (e.g. fuse) relating to a life support customer neutral integrity test – where a distributor will identify the source of a fault following detection from a network issued device. Rectification work to render the network safe is limited to distribution network infrastructure. <p>Such services do not include a service that has been separately classified including any activity relating to that service.</p>		

Ancillary services – Services closely related to common distribution services but for which a separate charge applies.

Design related services	Activities includes: <ul style="list-style-type: none"> 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. the provision of engineering consulting (related to the shared distribution network). 	Alternative control	Alternative control (specific monopoly service)
Connection application related	Activities include:	Alternative control	Alternative control (specific

Service group/Activities included	Further description	Current Classification 2014–19 ²⁰⁴	Proposed classification 2019–24
services	<ul style="list-style-type: none"> assessing connection applications or a request to undertake relocation of network assets as contestable works and preparing offers processing preliminary enquiries requiring site specific or written responses undertaking planning studies and associated technical analysis (e.g. power quality investigations) to determine suitable/feasible connection options for further consideration by applicants site inspection in order to determine the nature of the connection service sought by the connection applicant and ongoing co-ordination for large projects registered participant support services associated with connection arrangements and agreements made under Chapter 5 of the NER. 		monopoly service)
Access permits, oversight and facilitation	<p>Activities include:</p> <ul style="list-style-type: none"> 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. specialist services (which may involve design related activities and 	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included	Further description	Current Classification 2014–19 ²⁰⁴	Proposed classification 2019–24
	<p>oversight/inspections of works) where the design or construction is non-standard, technically complex or environmentally sensitive and any enquiries related to distributor assets.</p> <ul style="list-style-type: none"> • facilitation of generator connection and operation of the network. • facilitation of activities within clearances of distributor’s assets, including physical and electrical isolation of assets. • assessing an application from a manufacturer to consider approval of alternative material and equipment items that are not specified in the distributor’s approved materials list. 		
<p>Notices of arrangement and completion notices</p>	<p>A distributor may be required to perform work of an administrative nature 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, 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.</p> <p>A distributor may also be required to provide a completion notice (other than a notice of arrangement). This applies where the customer/developer requests distributor to provide documentation confirming progress of work. Usually associated with discharging contractual arrangements (e.g. progress payments) to meet contractual undertakings.</p>	<p>Alternative control</p>	<p>Alternative control (specific monopoly service)</p>
<p>Network related property services</p>	<p>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.</p>	<p>Alternative control</p>	<p>Alternative control (specific monopoly service)</p>

Service group/Activities included	Further description	Current Classification 2014–19 ²⁰⁴	Proposed classification 2019–24
	<p>Conveyancing inquiry services relating to the provision of property conveyancing information at the request of a customer.</p>		
<p>Site establishment services</p>	<p>Activities include, but not limited to:</p> <ul style="list-style-type: none"> • Site establishment, 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 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. • Site alteration, updating and maintaining national metering identifier (NMI) and associated data in market systems. • NMI extinction, processing a request by the customer or their agent for permanent disconnection and the extinction of a NMI in market systems. • Confirming or correcting metering or network billing information in market business to business or network billing systems, due to insufficient or incorrect information received from retailers or metering providers. 	<p>Alternative control</p>	<p>Alternative control (specific monopoly service)</p>
<p>Network safety services</p>	<p>Examples include:</p> <ul style="list-style-type: none"> • provision of traffic control services by the distributor where required. • fitting of tiger tails, high load escort. • de-energising wires for safe approach (e.g. for tree pruning). 	<p>N/A</p>	<p>Alternative control (potentially contestable)</p>

Service group/Activities included	Further description	Current Classification 2014–19 ²⁰⁴	Proposed classification 2019–24
	<ul style="list-style-type: none"> work undertaken to determine the cause of a customer fault where there may be a safety impact on the network or related component. 		
Network tariff change request	<p>Activities including a retailer's customer or retailer requesting an alteration to an existing network tariff (for example, a change from a Block Tariff to a Time of Use tariff), requiring the distributor to conduct tariff and load analysis to determine whether the customer meets the relevant tariff criteria.</p> <p>Where a distributor processes changes in its IT systems to reflect a tariff change request.</p>	Alternative control	Alternative control (specific monopoly service)
Services provided in relation to a Retailer of Last Resort (ROLR) event	<p>The distributors may be required to perform a number of services as a distributor when a ROLR event occurs. For example:</p> <p>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 handling subsequent enquiries.</p>	Alternative control	Alternative control (specific monopoly service)
Planned Interruption – Customer requested	<p>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.</p>	N/A	Alternative control (specific monopoly service)
Attendance at customers' premises to perform a statutory right where access is prevented.	<p>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).</p>	Alternative control	Alternative control (specific monopoly service)
Provision of training to third	<p>Training services provided to third parties that result in a set of learning</p>	N/A	Alternative control

Service group/Activities included	Further description	Current Classification 2014–19 ²⁰⁴	Proposed classification 2019–24
parties for network related access	outcomes that are required to obtain a distribution network access authorisation specific to a distributor’s network. Such learning outcomes may include those necessary to demonstrate competency in the distributor’s electrical safety rules, to hold an access authority on the distributor’s network and to carry out switching on the distributor’s network. Examples of training might include high voltage training, protection training or working near power lines training.		
Metering services			
Type 1 to 6 metering services ²⁰⁵	<p>Provide type 1 to 6 metering services as set out in chapter 7A of the NER (NT), including but not limited to:</p> <ul style="list-style-type: none"> • metering coordinator • metering provider including providing, installing, maintaining, inspecting, replacing and testing meters • meter reading including scheduled and special meter reads (e.g. move in and move out meter reading, final read on removed meter) • meter data services including collection, processing, management, delivery and storage of metering data. 	Standard control	Alternative control (specific monopoly service)
Type 7 metering services	Administration and management of type 7 metering installations in accordance with the chapter 7A of NER (NT) and jurisdictional requirements. Includes the processing and delivery of calculated metering data for unmetered loads, and the population and	Standard control	Standard control

²⁰⁵ Type 5 meters are currently not approved for use in the Northern Territory. When referring to type 1 to 6 metering services, this includes services relating to pre-payment meters.

Service group/Activities included	Further description	Current Classification 2014–19 ²⁰⁴	Proposed classification 2019–24
	maintenance of load tables, inventory tables and on/off tables.		
Customer requested provision of additional metering/consumption data	Customer requested provision of data in excess of requirements under rule 28 of the National Electricity Retail Rules (two requests per annum are permitted under this rule) or the Electricity Retail Supply Code (NT).	Alternative control	Alternative control (specific monopoly service)
Connection services			
Connection services	<p>Connection services include:</p> <p>Premises connection services includes any additions or upgrades to the connection assets located on the customer's premises (Note: excludes all metering services).</p> <p>Extensions include 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.</p> <p>Network augmentations include any shared network enlargement/enhancement undertaken by a distributor which is not an extension.</p>	Standard control	Standard control
Reconnections/Disconnections	<p>Disconnection and/or reconnection services (some provided in accordance with the National Energy Retail Rules). Examples include (but are not limited to):</p> <ul style="list-style-type: none"> • Disconnection visit (site visit only) • Disconnection visit (disconnection completed - technical) • Disconnection visit (disconnection completed) 	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included	Further description	Current Classification 2014–19 ²⁰⁴	Proposed classification 2019–24
	<ul style="list-style-type: none"> • Pillar box/pole top disconnection - completed • Reconnection/disconnection outside of business hours • Vacant property - site visit only • Vacant property disconnection (disconnection completed) • Shared service fuse replacement • Rectification of illegal connections • Temporary connections • Remove or reposition connection • Single phase to three phase 		

Unregulated distribution services

Distribution asset rental	Rental of distribution assets to third parties (e.g. office space rental, pole and duct rental for hanging telecommunication wires etc.).	N/A	Unclassified distribution service
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Appendix C: PWC's preferred service groupings and classification

To be clear, appendix B is our proposed approach to service classification of PWC's distribution services for the 2019–24 regulatory control period.

AER's proposed services		PWC comment / clarification	PWC proposed service classification
Common distribution services			
1	Common distribution services (formerly 'network services')	PWC interprets that this also includes: <ul style="list-style-type: none"> – Dismantling the network; – Meter data maintenance for operational purposes; – Emergency recoverable works arising from third party damage of PWC's assets. 	Standard Control Service
Ancillary services			
2	Design related services	PWC interprets that this also relates to: <ul style="list-style-type: none"> – Non-contestable only; – Pre-connection applications. 	Alternative Control Service
3	Connection application related services	PWC interprets that this to relate to: <ul style="list-style-type: none"> – Non-contestable connections only; – Work between the connection application and connection offer. 	Standard Control Service
4	Contestable network commissioning and decommissioning	This is not applicable: PWC has no contestable connection services.	Not applicable
5	Access permits, oversight and miscellaneous services	PWC interprets this to include issuing work permits.	Alternative Control Service
6	Notices of arrangement	PWC notes that "88B notices" do not exist in NT. There is an analogous planning arrangement.	Alternative Control Service

	AER's proposed services	PWC comment / clarification	PWC proposed service classification
7	Completion notice – other than Notice of arrangement		Alternative Control Service
8	Data gathering – failure to provide documentation	This is not applicable: PWC has no contestable connection services.	Not applicable
9	Network related property services		Alternative Control Service
10	Site establishment services	PWC interprets this to be a LNSP ³ function in the NT due to the lack of metering contestability. PWC's preference is that this be classified as SCS, rather than ACS as AER proposed.	Standard Control Service
11	Networks safety services	PWC interprets this to include cable location services.	Alternative Control Service
12	Customer vegetation defect works	PWC has an obligation under s.64 of the Electricity Reform Act to provide this service. PWC's preference is that this be classified as SCS, rather than ACS as AER proposed.	Standard Control Service
13	Network tariff change request		Alternative Control Service
14	Services provided in relation to a Retailer of Last Resort (ROLR) event	NT ROLR arrangements are in s.9 of the Electricity Retail Supply Code published by the Utilities Commission. PWC has obligations under the NT ROLR arrangements. PWC proposes that this be treated as an SCS, rather than ACS as proposed by the AER: – An ACS must be charged to a particular party. It is not clear who would be charged under NT ROLR arrangements. – As an SCS, the costs are recovered from the whole customer base.	Standard Control Service
15	Planned Interruption – Customer requested		Alternative Control Service
16	Attendance at customers' premises to perform a statutory right where access is prevented.		Alternative Control Service

AER's proposed services		PWC comment / clarification	PWC proposed service classification
17	Inspection services - Private electrical installations and accredited service providers (ASPs)	This is not applicable in NT: there are no contestable connection services	Not applicable
18	Authorisation of ASPs	This is required only for ASP who undertake non-contestable works at PWC's request	Alternative Control Service
19	Security lights (night watch)	PWC notes that this: <ul style="list-style-type: none"> - Will not be provided by PWC if it relates to public lighting; - Will be a quoted service if it is not a public lighting service; 	Alternative Control Service
20	Recoverable works	PWC interprets this to include: <ul style="list-style-type: none"> - Moving existing Infrastructure at a third party's request; - Reconfiguring existing infrastructure at a third party's request; - Other recoverable works not related to emergencies / faults. 	Alternative Control Service
21	De-energisations/Re-energisations	PWC interprets this to include: <ul style="list-style-type: none"> - Energising basic, standard and negotiated connections Connection of third party built infrastructure - Temporary connections This relates to services that are not at a retailer's request	Standard Control Service
Metering Services		Note: PWC will be the monopoly provider of metering services for Types 1-7 meters until at least 30 June 2024 as a result of jurisdictional arrangements in Chapter 7A of the National Electricity Rules that apply in the NT. The metering services to be provided by PWC under these arrangements is appended to this table.	
22	Type 1-4 metering services	See "PWC Metering Services" section of this table.	
23	Type 5 and 6 metering provision (prior to 1 December 2017)	See "PWC Metering Services" section of this table.	
24	Type 7 metering services	See "PWC Metering Services" section of this table.	

AER's proposed services		PWC comment / clarification	PWC proposed service classification
25	Meter reading and testing (legacy meters)	This is a consequence of the metering contestability rule change, ² which will not apply in the NT until at least 1 July 2024. not applicable to PWC. as it will not have any legacy meters before under jurisdictional arrangements.	Not applicable
26	Types 5 and 6 meter reading, maintenance and data services (legacy meters)	This is not applicable to PWC as it will not have any legacy meters before at least 1 July 2024 under jurisdictional arrangements.	Not applicable
27	Emergency maintenance of failed metering equipment not owned by the network (contestable meters)	This is not applicable to PWC as there will be no contestable meters before at least 1 July 2024	Not applicable
28	Meter recovery and disposal - type 5 and 6	This is included under services 22/23 - Types 1-6 metering services	
29	Distributor arranged outage for purposes of replacing metering	This is included under services 22/23 - Types 1-6 metering services	
30	Customer requested provision of additional metering/consumption data (legacy meters)	This is not applicable to PWC as there will be no contestable meters before at least 1 July 2024	Not applicable
31	Meter disposal	This is not applicable to PWC as there will be no contestable meters before at least 1 July 2024	Not applicable
32	Pre-payment meters	This is included under services 22/23 - Types 1-6 metering services	
Connection Services			
33	Premises connection assets	PWC interprets to include the following non-contestable connections: <ul style="list-style-type: none"> – Small customer connections; – Large customer connections; – Commissioning and energising third-party built infrastructure. 	Standard Control Service

AER's proposed services		PWC comment / clarification	PWC proposed service classification
34	Extensions		Standard Control Service
35	Augmentations	PWC interprets this to include: <ul style="list-style-type: none"> – removal of network constraints on a generator; – augmenting connection assets. 	Standard Control Service
36	Reconnections/Disconnections	PWC interprets this to relate to retailer-requested service orders and to include: <ul style="list-style-type: none"> – de-energisation of customer installations; – re-energisation of customer installations; – moving a point of attachment; – removing service connections; – temporary de-energisations. – rectification of illegal connections 	Alternative Control Service
37	Public lighting	PWC expects not to provide this service	Not applicable
38	Distribution asset rental		Unclassified Distribution Service
39	Contestable metering support roles	There will be no contestable metering support roles before at least 1 July 2024.	Not applicable
40	Non-standard connection services	PWC interprets this to include above standard reliability requested by a customer.	Alternative Control Service
41	Provision of electrical training to third parties		Unclassified Distribution Service
New	PWC provides access to PWC infrastructure		Unclassified Distribution Service
Non-distribution Services			
42	Generation assets		Non-Distribution Service
43	Water		Non-Distribution Service
44	Operation and maintenance of isolated distribution networks not part of the NEM		Non-Distribution Service
New	Contestable electrical works		Non-Distribution Service
	Contestable works		Non-Distribution Service
	Ad hoc HV testing		Non-Distribution Service
	Rental of minor apparatus		Non-Distribution Service

AER's proposed services		PWC comment / clarification	PWC proposed service classification
PWC Metering Services			
	Metering Co-ordinator (Type 1 to 6) ³	PWC is the de facto MC, MP and MDP for Type 1 to 6 meters in the NT until at least 30 June 2024.	Alternative Control Services
	Metering Provider (Type 1 to 6)		
	Meter Data Provider (Type 1 to 6)		
	Metering Co-ordinator (Type 7)	PWC is the de facto MC, MP and MDP for Type 7 meters in the NT until at least 30 June 2024.	Standard Control Services
	Metering Provider (Type 7)		
	Meter Data Provider (Type 7)		