Framework and approach

TasNetworks electricity transmission and distribution Regulatory control period commencing 1 July 2019

July 2017

AUSTRALIAN ENERGY REGULATOR

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Contents

Shortened forms

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

Shortened Form	Extended Form
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).

TasNetworks is the sole operator of the monopoly electricity transmission and distribution networks in Tasmania. The networks comprise the towers, poles, wires and transformers used for transporting electricity to homes and business. TasNetworks designs, constructs, operates and maintains the distribution and transmission electricity networks in Tasmania.

We make regulatory decisions on the revenue that TasNetworks can recover from its customers. We determine its revenue by an assessment of its efficient costs and forecasts. Our assessment is based on a regulatory proposals submitted by the network business in advance of a regulatory control period, in this case beginning 1 July 2019. The regulatory proposal sets out TasNetworks’ view on its expected costs, services, incentive schemes and required revenues. Our regulatory determinations set out our decisions on these issues.

The regulatory framework we administer is based on an incentive regime. We set a network business’ allowed revenue for a period (typically five years) based on the best available information, rigorous assessment and consideration of consumers’ views. A 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 Framework and Approach (F&A) is the first step in a two year process to determine efficient prices for electricity network services in Tasmania, although many aspects of the F&A relate specifically to distribution services. The F&A determines, amongst other things, which distribution services we will regulate and the broad nature of the regulatory arrangements. This includes an assessment of distribution 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 businesses prepare regulatory proposals.

The F&A applying to TasNetworks' transmission services covers a narrower range of matters relating particularly to the application of incentive schemes, the expenditure forecast assessment guideline and depreciation. This paper covers all F&A matters across distribution and transmission.

Five years ago, we published an F&A for TasNetworks’ electricity transmission network business[1] for the 2014–19 regulatory control period. Two years ago we published an F&A for TasNetworks' electricity distribution network business for the 2017–19 regulatory control

1 Previously known as Transend.

period.[2] The short regulatory control period for TasNetworks' distribution network was to align its regulatory schedule with TasNetworks' transmission network. For the 2019−24 regulatory control period we will make determinations for TasNetworks' distribution and transmission networks concurrently. This will minimise administrative costs incurred by TasNetworks and ourselves.

This F&A covers TasNetworks' merged transmission and distribution businesses in the one document to reflect TasNetworks' 'one business' approach.[3] Also, changes to the NER in November 2012 introduced new incentive schemes and allowed us to adopt improved approaches to assessing expenditure forecast by the network service provider.[4] The Power of Choice reforms also introduced changes to metering contestability.[5] Further, we are currently developing a new demand management incentive scheme (DMIS) and innovation allowance mechanism (Allowance Mechanism)[6] and have recently published a national ring-fencing guideline.[7]

Before reaching our proposed approach, we published a preliminary F&A for TasNetworks on 10 March 2017, seeking submissions from interested parties. Submissions closed on 21 April 2017, with four responses received, including a submission from our Consumer Challenge Panel, TasNetworks, SA Power Networks and Tasmanian Renewable Energy Alliance.[8] We also held a meeting with interested stakeholders on 12 April to discuss our preliminary F&A.

Table 1 summarises TasNetworks' determination process.

Table 1 TasNetworks determination process

Step	Date
AER published preliminary position F&A for TasNetworks	10 March 2017
AER to publish final F&A for TasNetworks	July 2017
TasNetworks to submit regulatory proposal to AER	January 2018

2 Previously known as Aurora Energy.

3 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 2.

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

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

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

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

8 All submissions are available on the AER's website at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2019-24-0/aer-position.

Step	Date
AER to publish Issues paper and hold 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
TasNetworks to submit revised regulatory proposal to AER	December 2018
Submissions on revised regulatory proposal and draft decision close	January 2019*
AER to publish TasNetworks determination for regulatory control period	April 2019

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

Source: NER, chapters 6.

This overview sets out our positions on:

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

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 assess if and how we will regulate TasNetworks' distribution services. Our service classification determines the nature of economic regulation, if any, applicable to distribution services. 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—unregulated distribution services must be provided through either a separate affiliate to the distributor or the distributor must demonstrate functional separation,[9] following the introduction of our Ring-Fencing Guideline.[10] Broadly,

9 Functional separation may include physical separation of offices, staff separation, accounting separation and separate branding/avoiding cross-promotion. See AER, *Ring-fencing guideline electricity distribution*, November 2016; AER,

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 separate to the regulated network business, unless it applies for, and receives, a waiver under the ring-fencing guideline.

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 services		Distribution services that are contestable will not be classified.	We have no role in regulating these services.
Non-distribution services		Services that are not distribution services.[11]	We have no role in regulating these services.

Source: AER

Our proposed position is to change the classification of some of TasNetworks' distribution services for the 2019−24 regulatory control period. Specifically, we proposed to reclassify new/emerging public lighting technology from negotiated to alternative control. Otherwise we

Electricity distribution ring-fencing guideline explanatory statement, November 2016, available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/electricity-ring-fencing-guideline-2016.

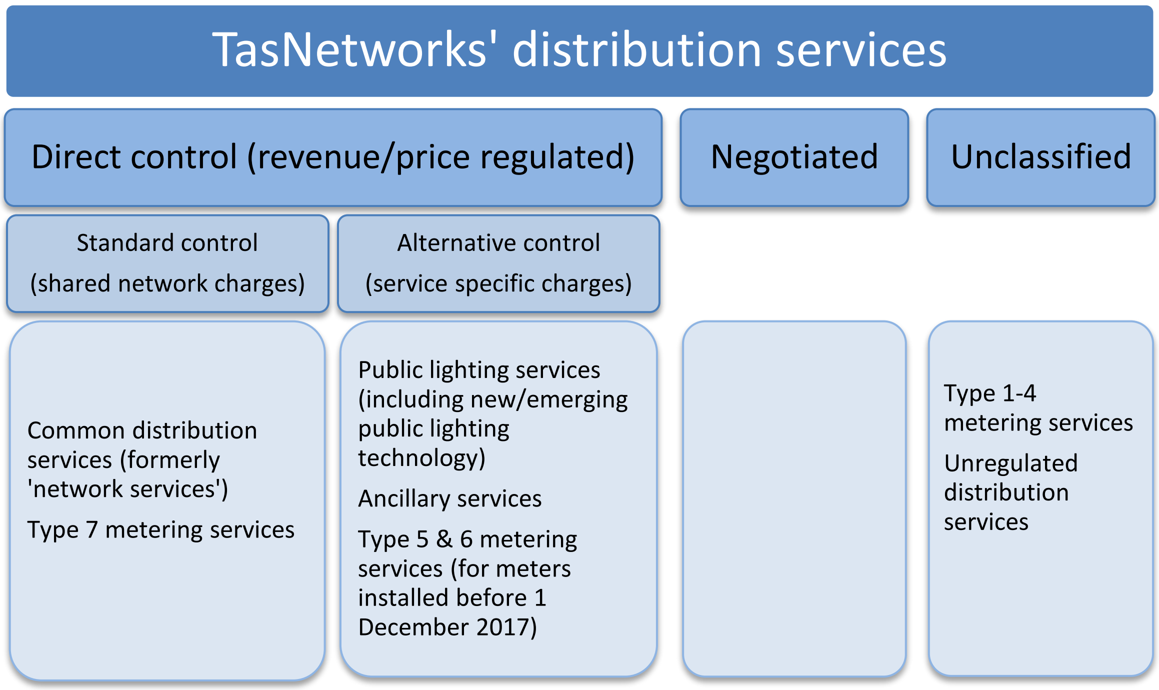
10 AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.

11 The NER defines a distribution service as a service provided by means of, or in connection with, a distribution system. NER, Chapter 10, glossary.

have clarified service descriptions to better align with the services being provided, create consistency and predictability across jurisdictions as far as practicable in how new distribution services might be classified.

Our proposed service classification for TasNetworks’ distribution services is set out in figure 1 below.

Figure 1 AER proposed classification of TAS distribution services



Source: AER

Our final F&A decision on service classification is not binding for our determination on TasNetworks' 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.[12]

Control mechanisms

Following on from service classifications, our determinations impose controls on direct control service prices and/or their revenues.[13] We may only accept or approve control mechanisms in a network’s regulatory proposal if they are consistent with our final F&A.[14] In deciding control mechanism forms, we must select one or more from those listed in the

12 NER, cl. 6.12.3(b).
13 NER, cl. 6.2.5(a).
14 NER, cl. 6.12.3(c).

NER.[15] 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 TasNetworks' distribution business is:

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

For standard control services the NER mandates the basis of the control mechanism must be the prospective CPI-X form or some incentive-based variant.[16]

Our final F&A decision on the form of control is binding on us and TasNetworks for the 2019−24 regulatory determination.[17] We may only vary our proposed control mechanism formulas in response to unforeseen circumstances.[18]

Incentive schemes

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

- Distribution and Transmission Service Target Performance Incentive Schemes (STPIS)
- Efficiency Benefit Sharing Scheme (EBSS)[19]
- Capital Expenditure Sharing Scheme (CESS)[20]
- Demand Management Incentive Scheme (DMIS) and Innovation Allowance Mechanism (Allowance Mechanism).

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

Application of our Expenditure Forecast Assessment Guideline

Our Expenditure Forecast Assessment Guideline[21] is based on a reporting framework allowing us to compare the relative efficiencies of transmission and distribution networks. Our proposed position is to apply the guideline, including its information requirements, to TasNetworks in the 2019−24 regulatory control period.

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15 NER, cl. 6.2.5(b).

16 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.

17 NER, cl. 6.8.1(b)(1)(i).

18 NER, cl. 6.12.3(c1).

19 The EBSS applies to both distribution and transmission businesses.

20 The CESS applies to both distribution and transmission businesses.

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

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

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

Depreciation

When we roll forward TasNetworks' transmission and distribution regulatory asset bases (RABs) for the upcoming 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 RABs as at 1 July 2024. In combination with our proposed application of the CESS this approach will maintain incentives for TasNetworks to pursue capital expenditure efficiencies. These improved efficiencies will benefit consumers through lower regulated prices.

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

Dual function assets

TasNetworks does not operate dual function assets. As such we are not required to make a decision on the application of either transmission or distribution pricing rules.[22]

22 Dual function assets are high-voltage transmission assets forming part of a distribution network. We decide whether to price dual function assets according to transmission or distribution pricing rules. Under transmission pricing rules the asset costs are recovered from all Tasmanian customers, like the cost of other transmission assets. Distribution pricing rules recover costs from only the customers of a specific distribution network.

1 Classification of distribution services

This chapter sets out our proposed approach on the classification of distribution services provided by TasNetworks in the 2019−24 regulatory control period. We don't consider the classification of TasNetworks' transmission services here because these are set in the National Electricity Rules. Service classification determines the nature of economic regulation, if any, applicable to distribution services. Applying the classification process prescribed in the NER, we may classify services so that we:

- directly control prices of some distribution services[23]
- allow parties to negotiate services and prices and only arbitrate disputes if necessary, or
- do not regulate some distribution services at all.

Our classification decisions therefore determine which services we will regulate and how distributors will recover the cost of providing those regulated services. We introduced our ring-fencing guideline for electricity distributors and our classification decisions will also settle ring-fencing obligations that will apply to TasNetworks for the 2019−24 regulatory control period.[24] For these reasons, we have closely reviewed the table of distribution services at appendix B.[25]

We are also aware that the Australian Energy Market Commission (AEMC) is currently assessing rule change proposals from the Council of Australian Governments Energy Council and Australian Energy Council on contestability of energy services.[26] 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.

23 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.

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

25 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 5.

26 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.

1.1 AER's proposed position

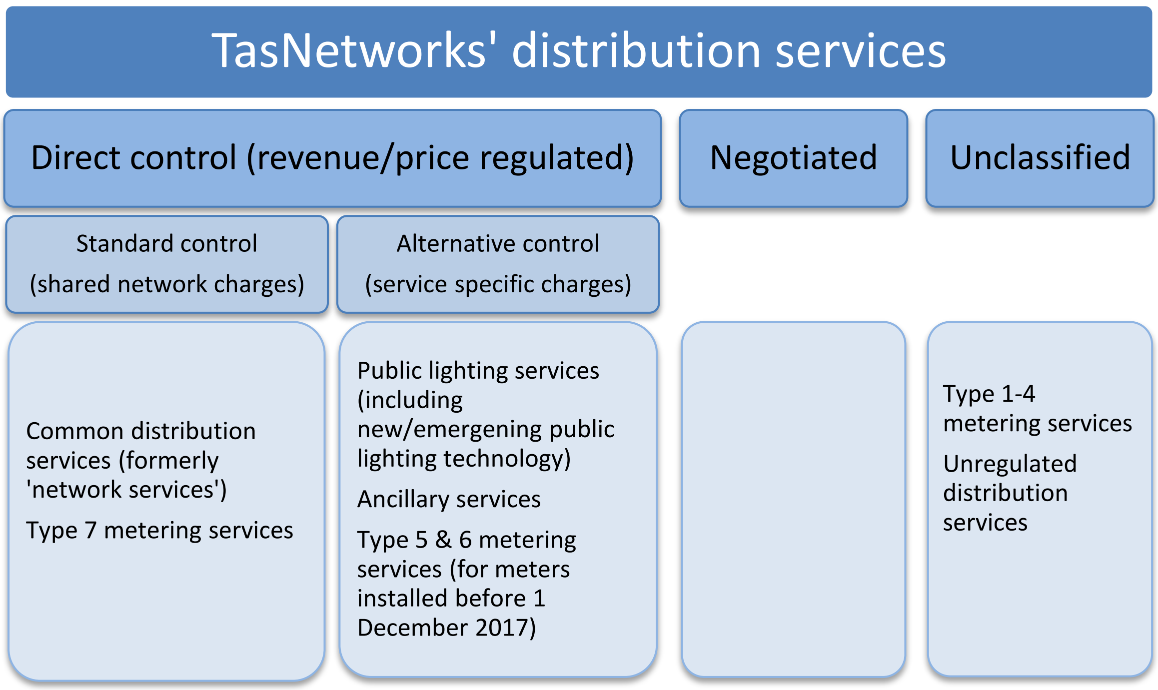
Overall, our proposed position is to change the classification of some Tasmanian distribution services for the 2019−24 regulatory control period.

Our proposed position is to group distribution services provided by TasNetworks as:

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

Figure 1.1 summarises our proposed classification of Tasmanian distribution services. Our assessment approach and reasons follow. TasNetworks noted that any AEMC rule change on service classification creates some uncertainty, but that it agreed with our proposed classification of services as set out below.[27]

Figure 1.1 AER proposed classification of TAS distribution services



Source: AER

27 TasNetworks, *Submission on AER preliminary framework and approach*, 21 April 2017, p. 3.

1.2 AER's assessment approach

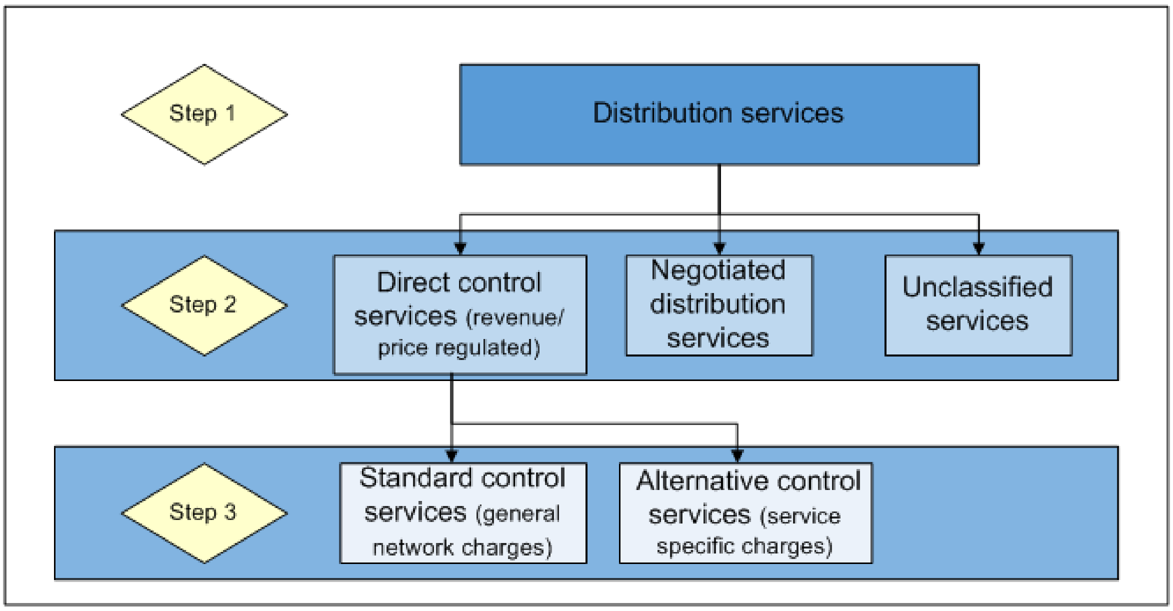
In conducting our assessment of distribution service classification, we commence on the basis that we:

- classify the service, rather than the asset – we can only decide on service classification if we understand what the service being provided is. That is, distribution service classification involves the classification of services distributors supply to customers rather than the classification of:
  - the assets used to provide such services;
  - the inputs/delivery methods distributors use to provide such services to
  - customers
  - services that consumers or other parties provide to distributors.
- classify distribution services in groups[28] – our general approach to service classification is to classify services in groupings rather than individually. This obviates the need to classify services one-by-one and instead defines a service cluster, that where a service is similar in nature it would require the same regulatory treatment. As a result, a new service with characteristics that are the same or essentially the same as other services within a group might simply be added to the existing grouping and hence be treated in the same way for ring-fencing purposes. This provides distributors with flexibility to alter the exact specification (but not the nature) of a service during a regulatory control period. Where we make a single classification for a group of services, it applies to each service in the group.
- In some circumstances, we may choose to classify a single service because of its particular nature. In addition, a distribution service that does not belong to any existing service classification may be 'not classified' and therefore be treated as an unregulated 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.

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.

28 NER, cl. 6.2.1(b).

Figure 1.2 Distribution service classification process



Source: NER, chapter 6, part B.

As illustrated by figure 2:

- We must first satisfy ourselves that a service is a 'distribution service' (step 1). The NER define a distribution service as a service provided by means of, or in connection with, a distribution system.[29] 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'.[30]
- 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.[31] 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

29 NER, chapter 10, glossary.
30 NER, chapter 10, glossary.
31 NER, cl. 6.2.1(c); NEL, s. 2F.

of regulation applied to services and the desirability of consistency in the form of regulation for similar services both within and beyond the jurisdiction.[32]

For services we intend to classify as direct control services, the NER requires us to have regard to a further range of factors.[33] 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:[34]

- 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.[35]

Our classification decisions determine how distributors will recover the cost of providing services.[36] 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 provide an opportunity for 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 ACS if it is either:

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

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

- Negotiating distribution service criteria—sets out the criteria distributors are to apply in negotiating the price, and terms and conditions, under which they supply distribution services. We will also apply the negotiating distribution service criteria in resolving disputes.

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32 NER, cl. 6.2.1(c).

33 NER, cl. 6.2.2(c).

34 NER, cl. 6.2.2(d).

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

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

- Negotiating framework—sets out the procedures a distributor and any person wishing to use a negotiated distribution service must follow in negotiating for provision of the service.

In the case of some distribution services, we may determine there is sufficient competition that there is no need for us to classify the service as either a direct control or negotiated 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. [37]

1.3 Reasons for AER's proposed position

This section sets out our proposed service classification and reasons for TasNetworks' 2019−24 regulatory control period for:

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

Appendix B contains a detailed table of our proposed classification of TasNetworks' distribution services.

1.3.1 Common distribution services

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

Common distribution services are concerned with providing safe and reliable electricity supply to customers.[38] Common distribution services are intrinsically tied to the network infrastructure and the staff and systems that support the shared use of the distribution network by customers. Customers use or rely on access to common distribution services on 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

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

38 NER, Chapter 10 glossary.

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 TasNetworks. 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 TasNetworks.

Ausgrid explained that its common distribution services description contains three key parts.[39] 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.

Ausgrid submitted that the substance of its amended description varies little from our preliminary F&A description, but provided better accuracy and less ambiguity.[40]

Our proposed position is to classify common distribution services as direct control services. TasNetworks holds an electricity distribution license which is the only distribution license in place for Tasmania.[41] Under section 17 of the *Electricity Supply Industry Act* (TAS) 1995, a person is prevented from distributing and supplying electricity unless they hold a licence

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

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

41 Licences are issued by Office of the Tasmanian Energy Regulator.

authorising them to do so. These arrangements create a regulatory barrier, preventing third parties from providing common distribution services.[42] 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.[43] Our proposed position is to retain the current standard control classification for common distribution services. There is no potential to develop competition in the market for common distribution services because of the barriers outlined above.[44] There would be no material effect on administrative costs for us, TasNetworks, users or potential users by continuing this classification.[45] We currently classify common distribution services (or 'network services') in Tasmania and all other NEM jurisdictions as standard control services.[46] Further, distributors provide common distribution services through a shared network and therefore cannot directly attribute the costs of these services to individual customers.[47]

Emergency recoverable works

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

Given that these services are provided in connection with a distribution system, we consider this a distribution service. However, we currently do not classify this service, treating it as an unregulated distribution service. This is because the cost of these works may be recovered through other avenues (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 control service. TasNetworks supported this approach.[48] 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

42 NER, cl. 6.2.1(c)(1); NEL, ss. 2F(a), (d) and (f).
43 NER, cl. 6.2.2(a).
44 NER, cl. 6.2.2(c)(1).
45 NER, cll. 6.2.2(c)(2), (3).
46 NER, cl. 6.2.2(c)(4).
47 NER, cl. 6.2.2(c)(5).
48 TasNetworks, *Submission on AER preliminary framework and approach*, 21 April 2017, p. 3.

emergency repairs from a third party, this payment or revenue, would be netted off. against the efficient expenditure incurred by a distributor in performing emergency recoverable works.[49] This prevents distributors from recovering the cost of emergency repairs twice—as a standard control charge across the broader customer base and from the responsible third party. Going forward, we propose to adopt this approach across all NEM jurisdictions.

1.3.2 Metering services

All electricity customers have a meter that measures the amount of electricity they use.[50] On 26 November 2015, the AEMC made a final rule that will open up competition in metering services and give consumers more opportunities to access a wider range of metering services.[51]

The competitive framework is designed to promote innovation and lead to investment in advanced meters that deliver services valued by consumers at a price they are willing to pay. Improved access to the services enabled by advanced meters will provide consumers with opportunities to better understand and take control of their electricity consumption and the costs associated with their usage decisions.[52]

The final rule alters who has overall responsibility for the provision of metering services by providing for the role and responsibilities of the Responsible Person to be performed by a new type of Registered Participant − a Metering Coordinator. Any person can become a Metering Coordinator subject to satisfying certain registration requirements.[53]

Retailers are required to appoint the Metering Coordinator for their retail customers. The final rule also includes a number of other features to support the competitive framework for the provision of metering services, including consumer protections[54] and an ability for consumers to opt out of having an advanced meter installed if they have an existing, working meter.[55]

The new arrangements will commence on 1 December 2017 and have required changes to the NER and the National Electricity Retail Rules (NERR).[56] Consequently, our proposed classification of some metering services will also change for the 2019−24 regulatory control period.

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49 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.

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

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

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

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

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

55 AEMC, *Final rule to increase consumers' access to new services information sheet*, 26 November 2015.

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

Type 1 to 4 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. Type 1 to 4 meters are competitively available[57] and we do not currently regulate them in Tasmanian or in most other jurisdictions—they are not classified and therefore are unregulated distribution services and our proposed position is for them to remain so.

Type 5 and 6 metering services

TasNetworks is currently the monopoly provider of type 5 (interval) and 6 (accumulation) meters. However, from 1 December 2017 (and therefore before the commencement of the next regulatory control period on 1 July 2019), metering services across the National Energy Market (NEM) will become contestable. Therefore, from 1 December 2017, households and other small customers who traditionally use these meter types may wish to change their metering provider and the type of meter they have. Further, TasNetworks (or any metering provider)[58] will no longer be permitted to install or replace existing meters with type 5 or 6 meters. As a result, our proposed position is to not classify these services for the 2019−24 regulatory control period.

While TasNetworks cannot install new type 5 and 6 meters from 1 December 2017, it will continue to operate and maintain existing type 5 and 6 meters until they are replaced. Therefore, TasNetworks will still recover the capital cost of type 5 and 6 metering equipment installed prior to 1 December 2017 as an alternative control service. This approach aligned with AEMC's Power of Choice recommendations to unbundle metering costs from shared network charges.[59]

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. TasNetworks is the monopoly provider of type 7 metering services in the Tasmania.[60]

We therefore consider that there is no potential to develop competition in the provision of type 7 metering services.[61] Currently, type 7 metering services in Tasmania are classified as alternative control services. However, a direct control and further, standard control

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

58 Except Power and Water Corporation in the NT, pursuant to chapter 7A NER (NT).

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

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

61 NER, 6.2.2(c)(1).

service classification is clearly more appropriate for this monopoly service.[62] We are not departing from the current direct control service classification[63] and a standard control classification would satisfy the NER's desire for consistency in regulatory approach to type 7 metering services across NEM jurisdictions.[64] Our proposed change in classification would have no impact on the administrative costs on us, TasNetworks, users or potential users.[65]

Ancillary services − Metering

TasNetworks will be required to provide ancillary metering services to support the metering contestability framework along with ongoing metering services to support existing type 5 and 6 meters. Some examples include:

- Type 5 and 6 meter final read − to conduct a final read on removed type 5 metering equipment as required by the Australian Energy Market Operator Service Level Procedure.[66]
- Distributor arranged outage for purposes of replacing meter − at the request of a retailer or metering coordinator, provide notification to affected customers and facilitate the disconnection/reconnection of customer metering installations where a retailer planned interruption cannot be conducted.[67]
- Type 5 and 6 meter recovery and disposal − at the request of the customer or their agent to remove or remove and dispose of a type 5 or 6 meter where a permanent disconnection has been requested.

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

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

Metering coordinator, metering provider, metering data provider

Under the competitive framework for metering, the roles of metering coordinator, metering provider and metering data provider may be performed by any registered person.[68]

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62 NER, cl. 6.2.1(d).

63 NER, cl. 6.2.1(d)(1).

64 NER, cl. 6.2.2(c)(4).

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

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

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

68 AEMC, *Rule determination, National Electricity Amendment (Expanding competition in metering and related services) Rule*

While we consider a metering coordinator, metering provider or metering data provider are distribution services, our proposed approach is to not classify these services.[69] That is, we propose to treat them as unregulated distribution services. Importantly, we consider that pre-existing type 5 and 6 metering services, as detailed in appendix B, already encompasses these roles and is reflected in the alternative control service charges.

To explain further, each distributor, as the current 'responsible person' under the NER, will be appointed as the metering coordinator as at 1 December 2017.[70] The distributors will remain in this role until such time as their type 5 or 6 meter is replaced or they receive notice from a retailer that it is replacing them as metering coordinator. While a distributor acts as the initial metering coordinator performing its current services like type 5 and 6 metering reading, maintenance and testing, we will classify it as an alternative control service. SA Power Networks supported this approach.[71]

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).

We currently classify TasNetworks' connection services, excluding augmentation, as direct control and further, as alternative control services. We have previously referred to these as 'basic connection services'. Our proposed approach is to continue this classification.

TasNetworks holds an electricity distribution licence which is the only distribution licence that is currently in place for Tasmania. Connection services involve work on, or in relation to, parts of TasNetworks' distribution network. We consider that, similar to common distribution services, there is a regulatory barrier preventing any party other than TasNetworks providing any connection services to its network.[72]

Because of this monopoly position, customers have limited negotiating power in determining the price and other terms and conditions on which TasNetworks provides these services. Furthermore, the scale of resources available to TasNetworks also likely prevents alternative

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

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

70 NER, cl. 11.86.7.

71 SA Power Networks, *Submission on AER preliminary framework and approach for NSW, ACT, TAS*, 21 April 2017, pp. 1−-2.

72 NEL, s. 2F(a).

providers from competitively providing connection services.[73] These factors support our view that TasNetworks possesses market power in providing connection services. Because of these barriers to competition from other service providers, we propose to continue classifying all connection services as direct control services.[74]

The nature of premises connection services and extensions 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.[75] We therefore propose to continue classifying these connection services as alternative control services.

We consider that retaining the current classification of premises connection services and extensions as alternative control services will have no material effect on administrative costs to us, TasNetworks, users or potential users.[76] This is because classifying these services as alternative control services is consistent with the current regulatory approach.[77]

Further, classifying premises connection services and extensions as alternative control services will facilitate introduction of competition, as being considered by the Tasmanian Government.[78]

We propose to classify connections requiring augmentation as direct control and standard control services. In most cases, if not all, augmentation of the network is a cost shared by all customers. We therefore consider that TasNetworks' possesses significant market power in providing augmentations to the shared network.[79] A third party can only perform an augmentation at a distributor's discretion. This creates a monopoly, which requires a stringent regulatory approach. Additionally, we have classified connection services in other NEM jurisdictions as direct control services.[80]

We must further classify direct control services as standard or alternative control services.[81] Our proposed approach is to classify augmentations as standard control services. This is consistent with the current regulatory approach because:

- There is no prospect for competition in the market for augmentations.[82] Our classification will not influence the potential for competition. Rather, the absence of competition is due to TasNetworks performing augmentations to ensure the safe and reliable supply of electricity to network customers.

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73 NEL, s. 2F(d).
74 NEL, s. 2F(a)(d).
75 NER, cl. 6.2.2(c)(5).
76 NER, cl. 6.2.2(c)(2).
77 NER, cl. 6.2.2(c)(4).
78 Tasmanian Government Department of State Growth, *Tasmanian Energy Strategy – Restoring Tasmania's energy advantage*, May 2015, p. 23.
79 NEL, s. 2F(d).
80 NER, cll. 6.2.1(c)(2) and (c)(3).
81 NER, cl. 6.2.2(c),
82 NER, cl. 6.2.2(c)(1).

- There would be no material effect on administrative costs to us, TasNetworks, users or potential users. This is because classifying augmentations as standard control services involves the whole customer base sharing the cost.[83]
- We currently regulate augmentations in all other NEM jurisdictions as direct and standard control services.[84]
- TasNetworks provides augmentations to benefit the shared network and cannot directly attribute costs to individual customers.[85]

For these reasons, we consider that it is clearly more appropriate to retain the current standard control service classification for augmentations.[86]

1.3.4 Ancillary services

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

The above factors create a regulatory barrier preventing any party other than TasNetworks providing ancillary services in their respective distribution area.[87] Because of this monopoly position, customers have limited negotiating power in determining the price and other terms and conditions on which the distributors provide these services. These factors contribute to the view that TasNetworks' possesses significant market power in providing ancillary services.[88]

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

Further, we intend to classify ancillary services as alternative control services because the TasNetworks provides these services to specific customers.[89] As such, the cost of each ancillary service is directly attributable to an individual customer.[90] This results in costs that are more transparent for customers.

We adopt this view even though ancillary services do not exhibit signs of competition or potential for competition. We also note that there would be no material effect on the

83 NER, cl. 6.2.2(c)(2).
84 NER, cl. 6.2.2(c)(3).
85 NER, cl. 6.2.2(c)(5).
86 NER, cl. 6.2.2(d).
87 NEL, s. 2F(a).
88 NEL, s. 2F.
89 NER, cl. 6.2.2(c)(5).
90 NER, cl. 6.2.2(c)(5) - this includes a small number of identifiable customers.

administrative costs to us, the distributors, users or potential users.[91] This is because classifying ancillary services as alternative control services is consistent with the current approach.

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

1.3.5 Public lighting

TasNetworks operates and maintains the majority of public lighting systems throughout Tasmania. TasNetworks provides these services on behalf of local councils and government departments responsible for public lighting in Tasmania.

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

- the operation, maintenance, repair and replacement of public lighting assets
- the alteration and relocation of public lighting assets, and
- the provision of new public lighting.[92]

We also propose to include new or emerging public lighting technology as part of the public lighting services group. Emerging public lighting technology relates to luminaires that TasNetworks does not provide at the time of our distribution determination. However, emerging public lighting technology may become available during the 2019−24 regulatory control period. Currently emergency public lighting technology is classified as a negotiated distribution service in Tasmania.

We intend to classify public lighting (including new or emerging public lighting technology) as a direct control service and further, as an alternative control service. TasNetworks supported this change in classification.[93] We did not receive any submissions from public lighting customers, potential customers or public lighting providers on this issue. Our reasons for this proposed change in classification follow.

We consider there to be significant barriers preventing third parties from providing public lighting services. While TasNetworks does not have a legislative monopoly over these services, a monopoly position exists. This is because TasNetworks owns the majority of public lighting assets. That is, other parties would need access to poles and easements for instance to hang their own public lighting assets.[94] However, TasNetworks owns and

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

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

93 TasNetworks, *Submission on AER preliminary framework and approach*, 21 April 2017, p. 3.

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

controls such supporting infrastructure. Therefore, similar to common distribution services, ownership of network assets restricts the operation, maintenance, alteration (including installing emergency public lighting technology) or relocation of public lighting services to TasNetworks. There is some limited scope for other parties to provide some public lighting services. For example, other parties may construct new public lights or perform works on independently owned public lighting assets.[95] Apart from these limited exceptions, we consider that a high barrier prevents third parties from entering this market. This limits competition in public lighting and results in TasNetworks' possessing significant market power.[96]

We currently regulate public lighting services in all NEM jurisdictions except the Australian Capital Territory and Northern Territory (where public lighting is government owned). We have classified some public lighting services in South Australia and Victoria as negotiated distribution services. However, the NER does not require us to classify similar services consistently between NEM jurisdictions.[97]

As direct control services, we must further classify public lighting services as either standard or alternative control services.[98] We intend to classify public lighting services as alternative control services for the following reasons:

- classifying public lighting services as alternative control services provides scope for third parties and new entrants to provide public lighting services.[99]
- classifying public lighting services as alternative control services may encourage other potential service providers to enter the market in the future, if a contestability regime is introduced. In the meantime, an alternative control classification supports the National Electricity Objective by ensuring distributors provide safe and reliable public lighting services to the community.[100]
- there would be no material effect on administrative costs to us, TasNetworks, users or potential users. This is because we are retaining the current classification[101] (although we are adding emerging public lighting technology to the public lighting services group).
- TasNetworks can directly attribute the costs of providing public lighting services to a specific set of customers. This includes local councils and other government agencies.[102]
- under an alternative control service classification, as part of our distribution determination, we would set a cost-reflective price[103] for public lighting services based on information provided by the distributor. This would remove the need for councils to

95 That is, assets, like poles, not owned by TasNetworks. NEL, s. 2F(f).
96 NEL, s. 2F(d).
97 NER, cll. 6.2.1(c)(3) and 6.2.2(c)(3) and (4).
98 NER, cl. 6.2.2(c).
99 NER, cl. 6.2.2(c)(1).
100 NER, cl. 6.2.2(c)(1).
101 NER, cl. 6.2.2(c)(2).
102 NER, cl. 6.2.2(c)(5).
103 A formula would be developed as part of the control mechanism that would set the inputs to be included in quoting a fee.

enter into negotiations with TasNetworks. Further, we are not satisfied that a negotiated distribution classification is beneficial, if negotiations between parties stall. This is evidenced by an ongoing dispute between SA Power Networks and a group of South Australian councils and Department of Transport, which has now reached arbitration to resolve public lighting prices from the 2010−15 regulatory control period. We do not consider that this type of uncertainty around public lighting prices that can result under a negotiated service classification is in the long term interests of consumers.

- based on submissions to us during the TasNetworks framework and approach for 2017−19, there does not appear to be an effective market for the majority of public lighting services in Tasmania and the ability of local councils to negotiate with TasNetworks appears quite uneven given their varying size and resources.[104]

For these reasons, we consider that public lighting services, including emerging public lighting technology, should be alternative control services.[105]

1.3.6 Unregulated distribution services

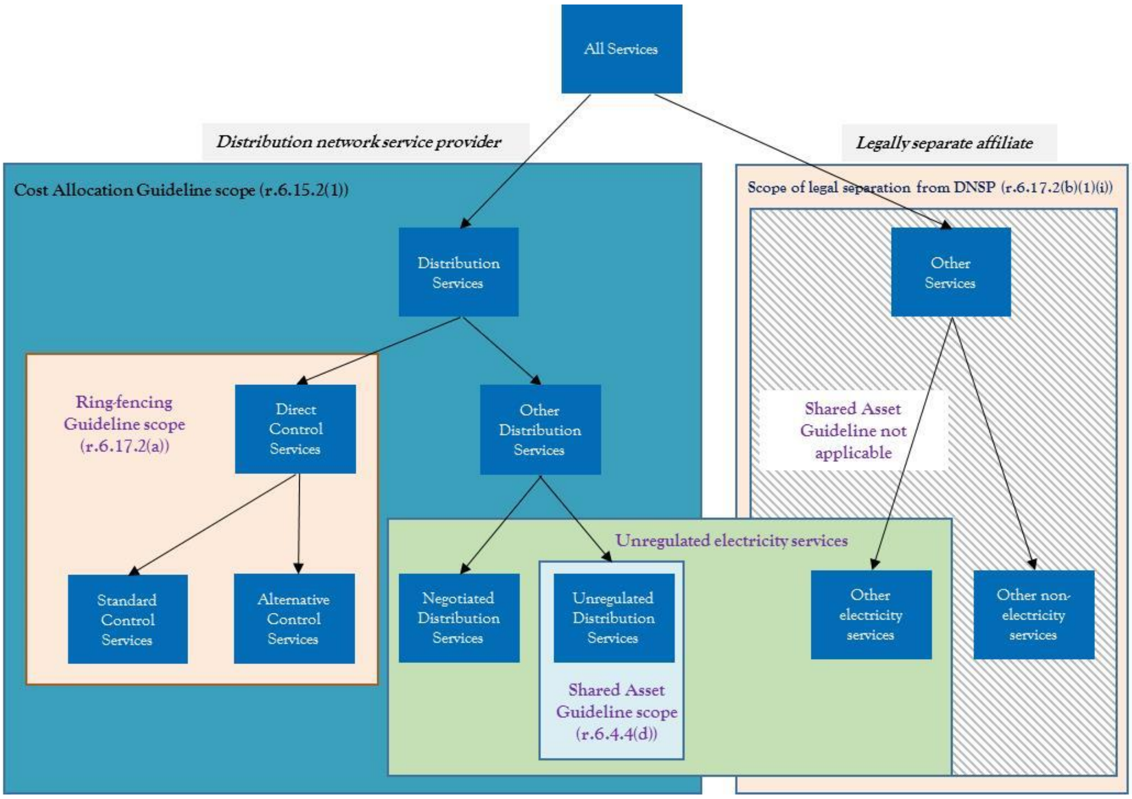
Unregulated distribution services is the term we us to describe distribution services which we have not classified as either direct control or negotiated services.[106] These services are provided on an unregulated basis and are potentially provided by other service providers in a competitive market. 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.[107] 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.[108] Under our ring-fencing guideline, any unregulated distribution service would be protected by functional and accounting separation. This removes the potential risk of a distributor benefitting from its privileged access to network information to gain a competitive advantage.

Figure 1.3 illustrates the interrelationship between service classification and ring-fencing obligations. Essentially, a distributor may only provide distribution services. Affiliated entities may provide other electricity services. For the purposes of this 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.[109]

104 AER, *Final framework and approach for TasNetworks 2017−19*, July 2015, p. 34.
105 NER, cl. 6.2.2(c)(3).
106 AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, p. 13.
107 AER, *Ring-fencing guideline electricity distribution*, November 2016; AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016.
108 AER, *Electricity distribution ring-fencing guideline explanatory statement*, November 2016, pp. 13−16.
109 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, such as the requirements to use a different brand, to use separate offices and to not share staff. Consequently, there are market effects of classifying a potentially contestable service as an alternative control service rather than an unregulated service.

We expect that there may be a number of distribution services that distributors identify subsequent to this F&A process or within the 2019−24 regulatory control period that would be unregulated. These unregulated distribution services must comply with the ring-fencing guideline until such time as we reconsider service classification for 2024−29 regulatory control period.

2 Control mechanisms

Our distribution determination must impose controls over the prices (and/or revenues) of direct control services.[110] This chapter sets out our decision, together with our reasons, on the form of control mechanisms to apply to TasNetworks' distribution 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.

This F&A paper does not address the form of control mechanism for TasNetworks' prescribed transmission services.[111] The NER requires a Transmission Network Service Provider's prescribed transmission services to be subject to a revenue cap form of control.[112]

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 TasNetworks' distribution services.

The form of control mechanisms in a distributor's regulatory proposal must be as set out in the relevant F&A paper.[113] 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.[114]

2.1 AER's decision

Our decision is to apply the following forms of control 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.

Our preliminary F&A set out the same forms of control for these services.[115]

We received two submissions on our preliminary F&A. Both submissions supported our preliminary positions on the forms of control. TasNetworks' submission supported a revenue cap for its standard control services and price caps for its alternative control services.[116]

110 NER, cl. 6.2.5(a).
111 NER, cl. 6A.10.1A(b).
112 NER, cl. 6A.3.1.
113 NER, cl. 6.12.3(c).
114 NER, cl. 6.12.3(c1).
115 AER, Preliminary framework and approach for TasNetworks distribution and transmission 2019–24, March 2017, p. 33.
116 TasNetworks, *Submission on AER Preliminary Framework and Approach*, 21 April 2017, p. 2.

CCP Sub-panel 13 also supported a revenue cap control mechanism however it did not comment on the control mechanism for alternative control services.[117]

2.2 AER's assessment approach

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

- the form of the control mechanisms[118]
- the formulae to give effect to the control mechanisms
- the basis of the control mechanism.[119]

The NER sets out the control mechanisms that may apply to both standard and alternative control services:[120]

- a schedule of fixed prices

A schedule of fixed prices specifies a price for every service provided by a distributor. The specified prices are escalated annually by inflation, the X factor and applicable adjustment factors. A distributor complies with the constraint by submitting prices matching the schedule in the first year and then escalated prices in subsequent years.

- caps on the prices of individual services (price caps)[121]

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 overs and unders account, whereby any revenue over recovery (under recovery) is deducted from (added to) the TAR in future years.

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

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117 Consumer Challenge Panel (Sub-panel) 13, *Submission on preliminary framework and approach for TasNetworks*, April 2017, p. 4.

118 NER, cl. 6.2.5(b).

119 NER, cl. 6.2.6(a).

120 NER, cl. 6.2.5(b).

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

A 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.

Our preliminary F&A on the control mechanisms for TasNetworks' standard control services only considered the continuation of the revenue cap, or adoption of price caps or an average revenue cap. We did not consider 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 also considered a price cap control mechanism, which was proposed by AGL.[122]

Our preliminary F&A set out why we did not consider the other forms of control but noted we would consider other forms where stakeholders considered it would best address the factors set out in clause 6.2.5 of the NER.[123]

We did not receive any submissions regarding an alternative form in response to our preliminary F&A. As noted, we received two submissions both of which supported the continuation of a revenue cap for TasNetworks' standard control services.

As such, our final F&A has not undertaken assessment of other forms of control. Instead our final F&A revisits our assessment from our preliminary F&A.

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

123 For more discussion on our reasoning see: AER, Preliminary framework and approach for TasNetworks distribution and transmission 2019–24, March 2017, pp. 35–36.

Our preliminary F&A on the control mechanisms for TasNetworks' alternative control services considered whether there was reason to depart from the current price caps in terms of the factors set out in clause 6.2.5(c) of the NER.

2.2.1 Standard control services

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

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

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

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

The basis of the control mechanism for standard control services must be of the prospective CPI–X form or some incentive-based variant.[124]

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 must have regard to the factors in clause 6.2.5(d) of the NER:

- the potential for competition to develop in the relevant market and how the control mechanism might influence that potential
- the possible effects of the control mechanism on administrative costs for us, the distributor and users or potential users
- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination

124 NER, cl. 6.2.6(a).

- 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.[125] 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.[126]

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

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

Our decision is to maintain a revenue cap for TasNetworks' 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 no 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.[127] We consider tariff structures are efficient if they reflect the underlying cost of supplying distribution services.

125 NER, cl. 6.2.6(b).
126 NER, cl. 6.2.6(c).
127 NER, cl. 6.2.5(c)(1).

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.[128] 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 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.
- 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.[129] The tariff structure statement should show how a distributor applied the distribution pricing principles[130] 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:[131]

> 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.

128 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.

129 NER, cl. 6.18.1A(a)(3).

130 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).

131 NER, cl. 6.18.5(a).

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.[132]

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

Through the 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 the 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.

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 also note that tariff reform brought about by the tariff structure statements is still in its infancy. As such, we may revisit the interaction between a control mechanism and efficient tariff structures in the future.

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.[133] 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 TasNetworks' standard control services would have the least complexity and administrative burden. The continuation of a revenue cap would impose no additional administrative costs for us, TasNetworks or users.

In contrast, additional administrative costs will be incurred by at least TasNetworks 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.

132 NER, cl. 6.12.3(k).
133 NER, cl. 6.2.5(c)(2).

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.[134] We note maintaining a revenue cap control mechanism for TasNetworks' 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.[135] We consider the continuation of a revenue cap control mechanism for TasNetworks' standard control services delivers consistent regulatory arrangements for these services across jurisdictions.

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.[136] This means that from 1 July 2019 all distributors' standard control services will be subject to a revenue cap control mechanism. Therefore maintaining TasNetworks revenue cap control mechanism ensures consistent regulatory arrangements for these services across 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 mechanism.

2.3.5 Revenue recovery

We consider 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 inefficiency is reduced when a distributor recovers additional revenue from price sensitive services through prices above marginal cost.[137]

134 NER, cl. 6.2.5(c)(3).

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

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

137 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.

For the preliminary F&A, AGL submitted that we review the control on TasNetworks' revenues in light of uncertainty around future network demand and utilisation.[138] 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.

Also under a revenue cap distributors have an incentive 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.[139] A systematic recovery of revenue above efficient cost recovery results in higher bills for consumers.[140] We consider a control mechanism that results in higher bills for consumers than necessary is not consistent with the national electricity objective.[141]

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.[142]

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.

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

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

140 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.

141 NEL, s. 7.

142 NEL, s. 7.

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.[143]

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 for our preliminary F&A, under a revenue cap falling demand creates price increases.[144] 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).[145] The inclusion of this estimated year helps smooth year-on-year revenue and tariff adjustments because the effects of the estimated year t–1 under or over recovery will have been largely accounted for when year t–1 becomes year t–2. That is, when year t–1 becomes year t–2 the adjustment to the TAR will only need to account for the difference between the estimated and actual under or over recovery and not the overall total under or over recovery.

In terms of stability across regulatory control periods, we consider an average revenue cap can result in greater price volatility compared to a revenue cap.[146] 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.

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

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

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

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

On balance, when weighing price flexibility and stability along with the other factors we have considered, our decision is to maintain TasNetworks' revenue cap control mechanism for standard control services. While we acknowledge a revenue cap has a higher likelihood of overall price instability during a regulatory control period, we consider our application of the rolling overs and unders 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.[147] 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.[148] 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.[149] We consider this provides a stronger incentive for a distributor to undertake demand side management within a regulatory control period compared to a control mechanism that has expected revenues varying with overall sales such as a price cap.

Under an average revenue cap or price cap control mechanism, a distributor's revenues are linked more closely to actual volumes of electricity distributed. As a result, distributors' profits increase with sales if the marginal revenue is greater than the marginal cost of providing services. Demand side management may not be attractive for distributors if such projects result in less revenue as a result 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.[150] 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

[147] Generally peak demand is referred to as the maximum load on a section of the network over a very short time period.
[148] AGL, *Consultation to amend or replace F&A for NSW, ACT and TAS*, 2 December 2016, p. 2.
[149] 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.
[150] NER, cl. 6.8.1(b)(2)(ii).

F&A paper.[151] Below is proposed formula to apply to TasNetworks' standard control services revenues. We consider that the formula gives effect to the revenue cap.

Figure 2.1 Proposed revenue cap to apply to TasNetworks' 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. $AAR_t = AR_t \times (1 + S_t)$ t = 1

4. $AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t) \times (1 + S_t)$ 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.

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.

151 NER, cl. 6.12.3(c1).

S_t is the s-factor for regulatory year t.[152] As it currently stands, the s-factor will incorporate any adjustments required due to the application of the AER's STPIS.[153]

However, we are currently undertaking a review of the STPIS. How the s-factor will apply within the revenue cap formula may depart from the current arrangement. Depending on the outcome of our review, provision to adjust revenues for performance against the STPIS may be made through either the *S* or *I* factors as set out in this final F&A. If the review is completed in time, TasNetworks may need to apply the revised STPIS for the 2019−24 regulatory control period. We will consider the application of the revised STPIS during the revenue determination process.

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

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

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

X_t 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 TasNetworks' alternative control services.[155] We propose classifying the following services as alternative control services:

- type 5 and 6 metering services (legacy meters)

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

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

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

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

- public lighting services
- ancillary services.

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

Unlike standard control services, the NER is not prescriptive on the basis of the control mechanism for alternative control services.[156] For example, the price caps could be based on a building block approach, or a modified building block cost build up. We have set out our 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 a departure from the current price cap controls for TasNetworks alternative control services would not have a significant impact on the potential development of competition. We consider the primary influence on competition development will be the classification of services as alternative control services. Chapter 1 discusses 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. The continuation of price caps will impose no additional administrative costs for us, TasNetworks or users. Additional administrative costs will be incurred at least to TasNetworks and us if an alternative control mechanism was applied to these services.

156 NER, cl. 6.2.6(c).

2.4.3 Existing regulatory arrangements

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

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 approach to the formulae that gives effect to the control mechanisms for alternative control services.[157] 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.[158]

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

Figure 2.2 Price cap formula to apply to TasNetworks' legacy metering, public lighting and ancillary services (fee based)

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

157 NER, cl. 6.8.1(b)(2)(ii).

158 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 Cities[159] 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 (positive or negative) with respect to regulatory year t, as determined by the AER.

Figure 2.3 Price cap formula to apply to TasNetworks' 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:

159 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.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[160] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

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

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

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

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

160 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.

3 Incentive schemes

This chapter sets out our proposed application of a range of incentive schemes to TasNetworks for the 2019−24 regulatory control period. We intend to apply the:

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

3.1 Service target performance incentive scheme

We have separate service target performance incentive schemes for distribution and transmission network service providers. We consider these separately below.

3.1.1 Distribution STPIS

This section sets out our proposed approach and reasons for applying the distribution STPIS to TasNetworks in the next regulatory control period.

Our national distribution STPIS[161] 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 distribution STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributor's incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (NEO).

The distribution 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 penalties) distributors for improved (or diminished) service compared to predetermined targets. Targets relate to service parameters pertaining to reliability and quality of supply, and customer service.
- A guaranteed service level (GSL) component composed of direct payments to customers[162] experiencing service below a predetermined level. This component only applies if there is not another GSL scheme already in place.[163]

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

162 Except where a jurisdictional electricity GSL requirement applies.

163 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.

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

- the maximum revenue at risk under the STPIS
- how the distributor's network will be segmented for the purpose of setting performance targets
- the applicable parameters for the s-factor adjustment of annual revenue
- performance targets for the applicable parameters in each network segment
- the criteria for certain events to be excluded from the calculation of annual performance and performance targets
- incentive rates that determine the penalties and rewards under the scheme.

TasNetworks may propose to vary the application of the distribution STPIS in its regulatory proposal.[164] We can accept or reject the proposed variation in our determination.

Each year we will calculate TasNetworks' s-factor based on its service performance in the previous year against targets, subject to the revenue at risk limit. Our national distribution STPIS includes a banking mechanism, allowing distributors to propose delaying a portion of the revenue increment or decrement for one year to limit price volatility for customers.[165] A distributor proposing a delay must provide in writing its reasons and justification as to why a delay will result in reduced price variations to customers.

Our distribution STPIS currently applies to TasNetworks with a cap on the maximum revenue at risk of ± 5 per cent. We are not applying the GSL component of the scheme as an existing GSL scheme exists under the Tasmanian Electricity Code (TEC).

AER's proposed position

Our proposed position is to continue to apply the distribution STPIS to TasNetworks in the next regulatory control period. We propose to:

- set revenue at risk for TasNetworks within the range of ± 5 per cent
- segment the network according to the TEC's supply reliability categories (critical infrastructure, high density commercial, urban, high density rural and low density rural)
- apply the system average interruption duration index (or SAIDI), system average interruption frequency index (or SAIFI) and customer service (telephone answering) parameters

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

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

- set performance targets based on TasNetworks' average performance over the past five regulatory years
- apply the method in the distribution STPIS for excluding specific events from the calculation of annual performance and performance targets
- apply the method and value of customer reliability (VCR) values as indicated in AEMO's 2014 Value of Customer Reliability Review final report to calculate the incentive rates.

We will not apply the GSL component if TasNetworks remains subject to a jurisdictional GSL scheme.

We are currently undertaking a review of the STPIS. If the review is completed in time, TasNetworks may need to apply the revised STPIS for the 2019–24 regulatory control period. We will consider the application of the revised STPIS during the revenue determination process.

AER's assessment approach

In deciding how to apply the scheme we have considered the requirements of the NER. The NER sets out certain requirements in relation to developing and implementing a STPIS.[166] These include:

Jurisdictional obligations

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

Benefits to consumers

We must take into account the benefits to consumers of applying the STPIS. This includes:

- the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any penalty or reward under the scheme
- the willingness of the customer or end user to pay for improved performance in the delivery of services
- balanced incentives
- the past performance of the distribution network
- any other incentives available to the distributor under the NER or the relevant distribution determination

166 NER, cl. 6.6.2(b).

- the need to ensure that the incentives are sufficient to offset any financial incentives the distributor may have to reduce costs at the expense of service levels
- the possible effects of the schemes on incentives for the implementation of non-network alternatives.

We considered the benefits to consumers of applying the STPIS when we developed the scheme. These considerations are set out in our final decision for the distribution STPIS.[167]

Reasons for AER's proposed position

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

Jurisdictional obligations

In Tasmania, the TEC sets out GSLs that apply to TasNetworks.[168] Our proposed approach to applying the STPIS in Tasmania is to not create duplication or compromise TasNetworks' 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 Tasmanian code remain in place. We will amend this position if the Tasmanian Government advises that these arrangements will cease to apply.

Benefits to consumers

We are mindful of the potential impact of the STPIS on consumers. Under the NER, we must consider customers' willingness to pay for improved service performance so benefits to consumers are sufficient to warrant any penalty or reward under the STPIS.[169]

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

The VCR estimates currently in our national STPIS are taken from studies conducted for the Essential Services Commission Victoria and Essential Services Commission of South Australia.[170] In September 2014 AEMO completed analysis of the VCR across the NEM.[171] We stated in our F&A paper for TasNetworks Distribution 2017−19 regulatory control period that we will apply a latest value for VCR through the distribution determination in calculating

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

168 OTTER, *Guideline - Guaranteed Service Level Scheme*, December 2007.

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

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

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

TasNetworks' incentive rates.[172] TasNetworks provided energy usage information based on AEMO's load classification of residential, commercial, industry and agriculture. Hence, for our 2017−19 determination, we calculated TasNetworks' VCR for the incentive rates by deriving it from its consumption data and AEMO's published segment VCR. We consider that this approach is still appropriate.

Our proposed approach is to maintain revenue at risk for TasNetworks at ± 5 per cent as we do not consider that a lower level would better meet the objectives of the STPIS. We did not receive any submissions on this issue.

CCP sub-panel 13 submitted that for the benefit of consumers, the F&A should make reference to the reliability standards processes as undertaken by OTTER to set reliability standards, their timing, likely issues and their important role in the regulatory process. This is because they are important exogenous inputs to STPIS and would assist consumers understanding of the fragmented approach.[173]

We consider the reliability standards set by OTTER and the performance targets under STPIS are unrelated. OTTER sets the network minimum reliability standard, to which TasNetworks must comply. The STPIS aims to maintain or improve the current reliability performance. TasNetworks' current performance is much better than OTTER's minimum requirements.

CCP sub-panel 13 also submitted that given the GSL scheme penalties are only a percentage of the AEMO estimates of VCR, consumers are being asked to support capital and operating expenditure (and hence network prices) based on VCR, an asymmetrical incentive arrangement exists for customers that experience the outages.[174] The GSL scheme currently in place within Tasmania is outside of our jurisdiction. However we note that the penalties and rewards under the distribution STPIS are aligned with the VCR. This means that though the GSL scheme penalties for outages may not align with the VCR, our STPIS penalties do. Thus, the incentives under our STPIS are not asymmetrical.

Balanced incentives

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

Defining performance targets

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

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172 AER, STPIS, November 2009.

173 Consumer Challenge Panel (Sub-panel 13), *Submission to TasNetworks 2019–24 regulatory control period - Preliminary framework and approach*, 2 May 2017, pp.4–5.

174 Consumer Challenge Panel (Sub-panel 13), *Submission to TasNetworks 2019–24 regulatory control period - Preliminary framework and approach*, 2 May 2017, p. 5.

The NER require us to consider past performance of the distributor's network in developing and implementing the STPIS.[175] Our preferred approach is to base performance targets on TasNetworks' average performance over the past five regulatory years.[176] Using an average calculated over multiple years instead of applying performance targets based solely on the most recent regulatory year limits a distributor's incentive to underperform in a specific year to make future targets less onerous.

Under this approach, distributors will only receive a financial reward for achieving reliability improvements. More importantly, a distributor can only retain the reward if it can maintain the reliability improvements. This is because, once an improvement is made, the benchmark performance targets will be adjusted to reflect the improved level of performance. If it allows reliability to decline in the future, the distributor will be penalised.

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

Interactions with our other incentive schemes

In applying the STPIS we must consider any other incentives available to the distributor under the NER or relevant distribution determination.[177] In Tasmania the STPIS will interact with our expenditure and demand management incentive schemes.

The efficiency benefit sharing scheme (EBSS) provides a distributor with an incentive to reduce operating costs. The STPIS counterbalances this incentive by discouraging cost reductions that lead to a decline in performance. The s-factor adjustment of annual revenue depends on the distributor's actual service performance compared to predetermined targets.

In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.[178]

The capital expenditure sharing scheme (CESS) rewards a distributor if actual capex is lower than the approved forecast amount for the regulatory year. Since our performance targets will reflect planned reliability improvements, any incentive a distributor may have to reduce capex by not achieving the planned performance outcome will be curtailed by the STPIS penalty.

The NER require us to consider the possible effects of the STPIS on a distributor's incentives to implement non-network alternatives to augmentation.

In the past we have received submissions requesting outages caused by failed non-network solutions be excluded from the STPIS. This is on the basis that the exclusion of these

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

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

177 NER, cll 6.6.2(b)(3)(iv).

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

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

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

3.1.2 Transmission STPIS

We create, administer and maintain the transmission STPIS in accordance with the requirements of the NER.[179] The transmission STPIS provides incentives for each TNSP to provide greater transmission network reliability when network users place greatest value on reliability, and improve and maintain the reliability of the elements of the transmission network most important to determining spot prices.[180]

The transmission STPIS consists of three components:

- a service component, which has four main parameters and various sub-parameters which act as key indicators of network reliability
- a market impact component (MIC), which encourages TNSPs to minimise the impact of network outages on the dispatch of generation
- a network capability component, which encourages TNSPs to undertake low cost projects to promote efficient levels of network capability from existing assets when most needed, while maintaining adequate levels of reliability.

Each regulatory year, under the scheme a TNSP's maximum allowed revenue (MAR) is adjusted based on its performance against the STPIS parameters in the previous calendar year. The STPIS can result in a maximum revenue increment or decrement between one and five per cent of the annual MAR.[181]

AER's proposed position

We propose to apply version 5 of the transmission STPIS to TasNetworks in the 2019–24 regulatory control period.

179 NER, cl. 6A.7.4(a).
180 NER, cl. 6A.7.4(b)(1).
181 NER, cl. 6A.7.4(b)(3).

Reasons for the AER's proposed position

We consider that applying the transmission STPIS will provide appropriate incentives for TasNetworks to:

- maintain and improve transmission network reliability
- improve and maintain the reliability of the elements of the transmission network to reduce the impact on wholesale market spot prices; and
- undertake relevant low cost projects to promote efficient levels of network capability from existing assets.

Currently, TasNetworks reports its transmission STPIS performance on a calendar year basis whereas it reports its distribution STPIS performance on a financial year basis. TasNetworks submitted that we should explore the possibility of aligning the reporting arrangements for transmission and distribution STPIS so that it can report performance on a financial year basis. It stated that a common reporting approach would assist all parties in better understanding performance across the combined networks.[182] TasNetworks wants to develop arrangements to transition the transmission STPIS to financial year reporting as part of its regulatory proposal.[183]

STPIS requires that TNSPs report their performance on a calendar year basis. To change this we need to amend the STPIS and our information guidelines – which require TNSPs to provide information on their performance on a calendar year basis. We explored the idea of moving to a financial year assessment in our final decision for STPIS version 5.[184] However, we did not do so at that time as this required amending the information guidelines, which was beyond the scope of the review.

We have decided not to amend the STPIS and the information guidelines to allow TasNetworks to report on a financial year basis for this F&A process. We consider amending the information guidelines and the Transmissions STPIS would require extensive consultation with all stakeholders and is beyond the scope of a regulatory determination.[185]

Applying the STPIS in the next regulatory control period

This section sets out the process that we will undertake to apply the transmission STPIS in the next regulatory control period. In its revenue proposal, TasNetworks must:

- Submit proposed values for the service component parameters.[186]

182 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 7.

183 TasNetworks, *Submission on AER preliminary framework and approach*, 21 April 2017, p. 5. TasNetworks, *Submission for exemption to elements of the Transmission STPIS Guideline*, 22 June 2017.

184 AER, *Final Decision Electricity transmission network service providers' service target performance incentive scheme*, September 2015, p. 44.

185 AER, *Final Electricity Transmission Network Service Providers Information Guideline Version 2*, April 2015.

186 STPIS, version 5, s. 3.2.

- Submit data for its market impact component in accordance with Appendix C for the preceding seven regulatory years.[187] It must submit a proposed value for a performance target, unplanned outage event limit and dollar per dispatch interval incentive.[188]
- Submit a network capability incentive parameter action plan.[189]

We will accept TasNetworks' proposed parameter values for the service, market impact and network capability components if the proposed values comply with STPIS version 5 clauses 3.2, 4.2 and 5.2 respectively.[190]

Service component

The service component will apply to TasNetworks to incentivise it to maintain and improve network availability and reliability.

In this component, TasNetworks can receive a revenue increment or decrement of up to 1.25 per cent of its MAR for the regulatory year.

Appendix A of the STPIS defines the service component parameters.[191] All service component parameters and sub-parameters apply to TasNetworks in STPIS version 5.[192]

We will assess whether TasNetworks' proposed performance targets, caps, floors and weightings comply with the parameter definitions, values and weightings set out in Section 3, appendix A and appendix E of the STPIS.

Our method of assessment of the parameter values is set out in section 3.2 of the STPIS. We may reject the proposed values where we are of the opinion that they are inconsistent with the objectives listed in clause 1.4 of the STPIS.[193]

Market impact component

The market impact component will be applied to TasNetworks to incentivise it to minimise the impact of its transmission outages that can affect NEM market outcomes.

In this component, TasNetworks will receive a financial incentive which falls within a range of minus one per cent (penalty) and plus one per cent (reward) of its maximum allowed revenue.[194]

We will assess TasNetworks' proposed parameter values using the methodology set out in section 4, appendices C and F of the STPIS.

187 STPIS, version 5, s. 4.2(a).
188 STPIS, version 5, s. 4.2(b).
189 STPIS, version 5, s. 5.2(b).
190 STPIS, version 5, October 2015.
191 STPIS, version 5, Appendix A.
192 STPIS, version 5, Appendix B.
193 STPIS, version 5, s. 3.2(l).
194 STPIS, version 5, s. 4.3.

Network capability component

- The network capability component will be applied to TasNetworks to incentivise it to identify and implement low cost one-off projects that will improve the capability of the transmission network at times most needed. AEMO will play a part in prioritising the projects to deliver best value for money for customers.
- In this component, TasNetworks will receive an annual allowance of up to a total of 1.5 per cent of MAR, but we may reduce the final payment (up to) minus 2 per cent of MAR, depending on the extent TasNetworks achieves its priority project improvement targets.[195]
- We will assess TasNetworks' network capability incentive parameter action plan in accordance with section 5.2 of the STPIS.

3.2 Efficiency benefit sharing scheme

The EBSS is intended to provide a continuous incentive for network service providers to pursue efficiency improvements in opex, and to fairly share these between the network service providers and consumers. Consumers benefit from improved efficiencies through lower network prices in future regulatory control periods.

TasNetworks proposed that the EBSS continue to apply to its transmission and distribution networks in the 2019–24 regulatory period.[196]

3.2.1 AER's proposed position

We intend to apply the EBSS to TasNetworks in the 2019–24 regulatory control period if we are satisfied the scheme will fairly share efficiency gains and losses between TasNetworks and consumers.[197] TasNetworks and CCP Sub-panel 13 supported our proposed application of the EBSS in the next regulatory control period.[198]

Our transmission and distribution determinations for TasNetworks for the 2019–24 regulatory control period will specify how we will apply the EBSS.

3.2.2 AER's assessment approach

The EBSS must provide for a fair sharing of opex efficiency gains and efficiency losses between a network service provider and network.[199] We must also have regard to the following factors in developing and implementing the E BSS:[200]

195 STPIS, version 5, s.5.3(b).

196 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 7.

197 NER, cl. 6.5.8(a).

198 TasNetworks, *Submission on AER preliminary framework and approach*, 21 April 2017, p. 2; Consumer Challenge Panel (Sub-panel 13), *Submission on the AER's preliminary F&A*, 2 May 2017, p. 2.

199 NER, cll. 6.5.8(a) and 6A.6.5(a).

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

3.2.3 Reasons for AER's proposed position

The EBSS applies to TasNetworks transmission in the 2014–19 period and to TasNetworks distribution in the 2017−19 regulatory control period.[201]

The EBSS is intrinsically linked to a network service provider's revealed costs. In assessing a service provider’s opex proposal, we seek to identify an efficient opex amount in the base year (the ‘revealed costs’ of the service provider), which we use to develop an alternative estimate of total opex for the 2019–23 regulatory control period. We compare this to a service provider’s opex proposal when assessing it against the opex criteria. If we approve opex that reflects a service provider's revealed costs and apply the EBSS, and the service provider then makes an incremental efficiency gain, it will receive a reward through the EBSS. The lower revealed costs will inform our assessment of the service provider'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

3.3 Capital expenditure sharing scheme

The CESS provides incentives to network service providers to undertake efficient capex by further rewarding efficiency gains and penalising efficiency losses. Consumers benefit from improved efficiency through lower network prices in the future. This section sets out our

200 NER, cll. 6.5.8(c) and 6A.6.5(b).

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

proposed approach and reasons for how we intend to apply version 1 of the CESS to TasNetworks distribution and transmission in the next regulatory control period.[202]

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

The CESS works as follows:

- We calculate the cumulative underspend or overspend 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 amount 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 amounts.[203] We can also make further adjustments to account for deferral of capex and ex post exclusions of capex from the RAB.
- The CESS payments will be added to or subtracted from the distributor's regulated revenue as a separate building block in the next regulatory control period.

Under the CESS a distributor retains 30 per cent of the financing benefit or cost of any underspend or overspend amount, while consumers retain 70 per cent of the financing benefit or cost of any underspend or overspend amount.

3.3.1 AER's proposed position

We intend to apply the CESS, as set out in our capex incentives guideline,[204] to TasNetworks distribution and transmission businesses in the 2019−24 regulatory control period. TasNetworks and CCP sub-panel 13 supported our intention to apply the CESS in the next regulatory control period.[205]

3.3.2 AER's assessment approach

In deciding whether to apply a CESS to a network service provider, and the nature and details of any CESS to apply to a network service provider, we must:[206]

202 The distribution and transmission CESS are substantively the same, except that there is an exclusion from the transmission CESS for projects linked to the network capability incentive parameter action plan.

203 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.

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

205 TasNetworks, *Submission on AER preliminary framework and approach*, 21 April 2017, p.2; Consumer Challenge Panel (Sub-panel 13), *Submission on preliminary framework and approach for TasNetworks*, April 2017, p. 4.

206 NER, cll. 6.5.8A(e), 6A.6.5A(e).

- make that decision in a manner that contributes to the capex incentive objective set out in the NER[207]
- consider the CESS principles,[208] capex objectives,[209] 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

TasNetworks proposed that the CESS continues to apply to its transmission and distribution networks in the 2019–24 regulatory period.[210]

TasNetworks is currently subject to a CESS. As part of our Better Regulation program we consulted on and published version 1 of the capex incentives guideline which sets out the CESS.[211] The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.[212] 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, STPIS, and DMIS—which TasNetworks will be subject to in the next regulatory control period.

For capex, the sharing any underspend and overspend amounts happens at the end of each regulatory control period when we update a network service providers' RAB to include new capex. If a network service provider 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 network service provider to spend less than its forecast capex declines throughout the period.[213] Because of this a network service provider may choose to spend capex earlier, or spend on capex when it may otherwise have spent on

207 NER, cll. 6.4A(a) and 6A.5; the capex criteria are set out in cll. 6.5.7(c) and 6A.6.7 of the NER.

208 NER, cll. 6.5.8A(c), 6A.6.5A(c).

209 NER, cll. 6.5.7(a), 6A.6.7(a).

210 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 7.

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

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

213 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.

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

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

3.4 Demand management incentive scheme 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 TasNetworks in the 2019−24 regulatory control period.

We apply a demand management incentive scheme (current scheme) in our distribution determination for the 2017−19 regulatory control period.[214]

Our current scheme consists of two parts. The first is the demand management innovation allowance (DMIA), which is incorporated into TasNetworks' revenue allowance for each year of the regulatory control period. TasNetworks prepares an annual report on their expenditure under the DMIA in the previous year, which we then assess against specific criteria.[215] The second element is a forgone revenue component, which allows a distributor to recover forgone revenues that are directly attributable to a non-tariff demand management project or program approved under the DMIA. Compensation for foregone revenue is not applied where a distributor is subject to a revenue cap rather than a price cap.

Currently, only the DMIA (Part A of the scheme) applies to TasNetworks because it is subject to a revenue cap form of control. As a revenue cap will apply in the next regulatory control period, compensation for foregone revenue will not be relevant to TasNetworks in the next regulatory control period.[216]

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

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

216 Refer to Chapter 2 on Control mechanisms of this paper.

On 20 August 2015, the AEMC published a rule determination changing the application of the current scheme.[217] 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 paper, 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.[218] 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 consequent to the rule change in August 2015, to apply to TasNetworks in the 2019−24 regulatory control period.[219]

The Tasmanian Renewable Energy Alliance and TasNetworks accepted our preliminary position to apply the new DMIS and Allowance Mechanism in the next regulatory control period.[220] However, TasNetworks also noted that if we adopt a significantly different DMIS to the current scheme, this would likely affect its ability to forward plan for 2019−24.[221] We are considering the concerns TasNetworks raised in its submission to the DMIS consultation as part of that process.

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

218 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 .

219 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 7.

220 Tasmanian Renewable Energy Alliance, *Response to preliminary framework and approach TasNetworks 2019−24*, 21 April 2017, p. 1; TasNetworks, *Submission on AER preliminary framework and approach*, 21 April 2017, p. 5.

221 TasNetworks, *Submission on AER preliminary framework and approach*, 21 April 2017, p. 5.

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 TasNetworks.[222] These are:

DMIS Objective

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

Benefits to consumers

- The DMIS should reward TasNetworks 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 TasNetworks 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.

222 NER, cl. 6.6.3(c).

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 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.[223] 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.[224]

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.[225] 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.[226] 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.

223 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.

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

225 NER, cl. 6.6.3(c)(2).

226 NER, cl. 6.6.3(c)(3).

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 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 TasNetworks.[227] These are:

Allowance Mechanism Objective

- The Allowance Mechanism should provide TasNetworks 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 TasNetworks in the next regulatory control period.

Distributors have historically planned their network investment to provide sufficient capacity for the periods where the network elements reach maximum utilisation levels. Peak demand

227 NER, cl. 6.6.3A(c).

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.

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 another 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 forecast assessment guideline (the EFA guideline)[228] including the information requirements applicable to TasNetworks for the 2019−24 regulatory control period. The EFA guideline sets out our expenditure forecast 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 forecast expenditure, 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 TasNetworks to advise us by 30 June 2017 of the methodology they propose to use to prepare their forecasts.[229] In the F&A we must advise whether we will deviate from the EFA guideline.[230] This will provide clarity on how we will apply the EFA guideline and the information TasNetworks should include in its regulatory proposals. This contributes to an open and transparent process makes our assessment of expenditure forecasts more predictable.[231] 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.[232]

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 EFA guideline is flexible and recognises that we may employ a range of different estimating techniques to assess an expenditure forecast. TasNetworks had previously raised concerns regarding our benchmarking method

228 We were required to develop the EFA guideline under clauses 6.4.5, 6A.5.6, 11.53.4 and 11.54.4 of the NER. We published the guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864.

229 NER, cl.6.8.1A(b)(1), 6A.10.1B(b)(1), 11.60.3(c) and 11.58.4(n).

230 NER, cl. 6.8.1(b)(2)(viii) and 6A.10.1A(b)(5).

231 As per the requirements of NER, cll. 6.8.2(c2) and 6A.10.1(h)TasNetworks is required to submit expenditure assessment information in their regulatory proposal. TasNetworks' 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.

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

and approach.[233] However, in its response to our preliminary F&A approach, TasNetworks supported the application of the EFA guideline.[234] TasNetworks noted it would continue to analyse our benchmarking results and provide commentary as part of its revenue proposal.[235]

In its submission, SA Power Networks considered we should we commence an open and transparent consultation process to review our benchmarking approach following the Full Federal Court appeal outcome.[236]

The Full Federal Court handed down its decision 24 May 2017.[237] We are carefully considering this decision.

We will continue to develop and use economic benchmarking to inform our expenditure decisions. Economic benchmarking remains a tool in assessing the relative efficiency of network services providers. It also provides a source of information to assist both service providers and other interested parties about the relative productivity of individual businesses and the trends in productivity for the industry.

233 As requested by TasNetworks in its letter to the AER: *TasNetworks' Framework and approach for the 2019−24 determination*, 27 October 2016, p. 8.

234 TasNetworks, *Response to AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 2.

235 TasNetworks, *Response to AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 6.

236 SA Power Networks, *Response to AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, p. 2–3.

237 The Full Federal Court handed down its final directions on 4 July 2017.

5 Depreciation

As part of the process of rolling forward a network service provider'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 TasNetworks' RAB is rolled forward to the commencement of the 2024–29 regulatory control period. Our approach applies to both TasNetworks' transmission and distribution network businesses.

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 network service provider; 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 the network service provider 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.[238] 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 network service provider 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 network service provider 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 network service provider 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 network service

238 AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 10–12.

provider's incentive on capex as the network service provider's does not lose the full cost of any overspend and is not able to keep all the benefits of any 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 TasNetworks. We consider this approach will provide sufficient incentives for TasNetworks 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 network service provider's RAB at the commencement of the following regulatory control period.[239]

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.[240] Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:[241]

- 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 TasNetworks at the commencement of the 2024–29 regulatory control period. TasNetworks supported our preliminary position to use the forecast depreciation approach to establish the opening RAB.[242] The CCP (Sub-panel 13) also agreed with our preliminary position on the depreciation approach.[243]

239 NER, cll. S6.2.2B and S6A.2.2B.
240 NER, cll. 6.4A(b)(3) and 6A.5A(b)(3).
241 NER, cll. S6.2.2B and S6A.2.2B.
242 TasNetworks, *Submission on AER preliminary framework and approach*, 21 April 2017, p. 2.
243 Consumer Challenge Panel (Sub-panel13), *Submission on preliminary framework and approach for TasNetworks*, April 2017, p. 4.

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.[244]

Our approach is to apply forecast depreciation except where:

- there is no CESS in place and therefore the power of the capex incentive may need to be strengthened, or
- a network service provider'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 network service provider to achieve efficiency gains over the regulatory control period in most circumstances.

The opening RAB at the commencement of the 2019–24 regulatory control period will be established using forecast depreciation. This is consistent with our previous determinations that apply to TasNetworks' distribution network for the 2017–19 regulatory control period and transmission network for the 2014–19 regulatory control period. The use of forecast depreciation to establish the opening RAB for the commencement of the 2024–29 regulatory control period therefore maintains the current approach. TasNetworks is currently subject to a CESS under its transmission and distribution determinations and we propose to continue to apply the CESS to TasNetworks in the 2019–24 regulatory control period. We discussed this in section 3.3.

For TasNetworks, 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.[245] 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.

244 AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 10–12.

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

6 Dual function assets

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

TasNetworks does not currently own, control or operate any dual-function assets, nor did it own, control or operate any dual function assets at the time of the last determination. Therefore, we are not required to, and will not; make any decision under the NER regarding dual-function assets.[246]

246 NER, cll. 6.8.1(b)(1)(ii) and 6.25(b).

Appendix A: Rule requirements for classification

We must have regard to four factors when classifying distribution services.[247]

- 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.[248]
- 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)[249]
- the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)[250]
- any other relevant factor.[251]

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247 NER, cl. 6.2.1(c).
248 NEL, s. 2F.
249 NER, cl. 6.2.1(c)(2).
250 NER, cl. 6.2.1(c)(3).
251 NER, cl. 6.2.1(c).

The NER specify additional requirements for services we have regulated before.[252] They are:

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

We must have regard to six factors when classifying direct control services as either standard control or alternative control services.[253]

- 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.[254]

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.

252 NER, cl. 6.2.1(d).
253 NER, cl. 6.2.2(c).
254 NER, cl. 6.2.2(c).

Appendix B: Proposed service classification of Tasmanian distribution services[255]

Service group/Activities included in service group	Further description	Current Classification 2017−19	Proposed classification 2019−24
Common distribution services			
Common distribution services (formerly 'network services')	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: • 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

255 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.

Service group/Activities included in service group	Further description	Current Classification 2017−19	Proposed classification 2019−24
	• 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. • private pole inspection directed by Tasmanian Government. Such services do not include a service that has been separately classified including any activity relating to that service.		
Ancillary services – Services closely related to common distribution services but for which a separate charge applies.			
Design related services	Activities includes: • provision of design information, design rechecking services in relation to connection and relocation works provided contestably. • specialist services where the design is non-standard,	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included in service group	Further description	Current Classification 2017−19	Proposed classification 2019−24
	technically complex or environmentally sensitive and any enquiries related to distributor assets. • the provision of engineering consulting (related to the shared distribution network).		
Connection application related services	Activities include: • 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.	Alternative control	Alternative control (specific monopoly service)
Access permits, oversight and facilitation	Activities include: • 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.	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included in service group	Further description	Current Classification 2017−19	Proposed classification 2019−24
	• 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. • 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.		
Notices of arrangement	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	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included in service group	Further description	Current Classification 2017−19	Proposed classification 2019−24
	of arrangement.		
Network related property services	Property tenure services related to obtaining deeds of agreement, deeds of indemnity, leases, easements or other property tenure in relation to property rights associated with connection or relocation. Conveyancing inquiry services relating to the provision of property conveyancing information at the request of a customer.	Alternative control	Alternative control (specific monopoly service)
Site establishment services	Activities include, but not limited to: • 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 B2B or network billing systems, due to insufficient or incorrect information received from	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included in service group	Further description	Current Classification 2017−19	Proposed classification 2019−24
	retailers or metering providers.		
Network safety services	Examples include: • 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). • work undertaken to determine the cause of a customer fault where there may be a safety impact on the network or related component.	N/A	Alternative control
Network tariff change request	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. Where a distributor processes changes in its IT systems to reflect a tariff change request.	Alternative control	Alternative control (specific monopoly service)
Services provided in relation to a Retailer of Last Resort (ROLR) event	The distributors may be required to perform a number of services as a distributor when a ROLR event occurs. For example: Preparing lists of affected sites and reconciling data with AEMO listings, arranging estimate reads for the date of the ROLR event, preparing final invoices and miscellaneous charges for affected customers, extracting customer data,	Alternative control	Alternative control (specific monopoly service)

Service group/Activities included in service group	Further description	Current Classification 2017−19	Proposed classification 2019−24
	providing it to the ROLR and handling subsequent enquiries.		
Planned Interruption – Customer requested	Where the customer requests to move a planned interruption and agrees to fund the additional cost of performing this distribution service outside of normal business hours.	N/A	Alternative control (specific monopoly service)
Attendance at customers' premises to perform a statutory right where access is prevented.	A follow up attendance at a customer's premises to perform a statutory right where access was prevented or declined by the customer on the initial visit. This includes the costs of arranging, and the provision of, a security escort or police escort (where the cost is passed through to the distributor).	Alternative control	Alternative control (specific monopoly service)
Inspection services – private electrical installations	Inspection of and reinspection by a distributor of: • private electrical wiring work undertaken by an electrical contractor • private inspection of privately owned low voltage or high voltage network infrastructure (i.e. privately owned distribution infrastructure before the meter).	N/A	Alternative control (specific monopoly service)
Provision of training to third parties for network related access	Training services provided to third parties that result in a set of learning 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.	N/A	Alternative control

Service group/Activities included in service group	Further description	Current Classification 2017−19	Proposed classification 2019−24
Security lights	Customer requested flood lighting services.	Alternative control	Alternative control (potentially contestable)
Metering services − TasNetworks will remain responsible for the provision of type 5 and 6 meters up to 30 November 2017. TasNetworks will continue to be responsible for those meters until they are replaced (and entitled to levy associated charges). We refer to these meters as ‘legacy meters’. New meters (that will be type 1 to 4 meters) installed from 1 December 2017 are referred to as ‘contestable meters’.			
Type 1 to 4 metering services	Type 1 to 4 meters and supporting services are competitively available.	Unclassified	Unclassified
Type 5 and 6 meter provision (before 1 December 2017)	Recovery of the capital cost of type 5 and 6 metering equipment installed before 1 December 2017.	Alternative control	Alternative control (specific monopoly service)
Type 7 metering services	Administration and management of type 7 metering installations in accordance with the NER and jurisdictional requirements. Includes the processing and delivery of calculated metering data for unmetered loads, and the population and maintenance of load tables, inventory tables and on/off tables.	Alternative control	Standard control
Types 5 and 6 meter maintenance, reading and data services (legacy meters)	Meter maintenance covers works to inspect, test, maintain and repair meters. Meter reading refers to quarterly or other regular reading of a meter. Metering data services are those that involve the collection, processing, storage and delivery of metering data and the management of relevant NMI Standing Data in accordance with the Rules.	Alternative control	Alternative control (specific monopoly service)
Special meter reading and testing	Special meter reading and testing services include:	Alternative control	Alternative control (specific

Service group/Activities included in service group	Further description	Current Classification 2017−19	Proposed classification 2019−24
(legacy meters)	• Special meter reading for type 5 and 6 meters and move in and move out metering reading • Type 5 meter final read on removed type 5 metering equipment • Special meter test (for type 5 and 6 meter) • Type 5 and 6 non-standard meter data services • Type 5 and 6 current transformer testing.		monopoly service)
Emergency maintenance of failed metering equipment not owned by the distributor (contestable meters)	The distributor is called out by the customer or their agent (e.g. retailer, metering coordinator or metering provider) due to a power outage where an external metering provider's metering equipment has failed or an outage has been caused by the metering provider and the distributor has had to restore power to the customer's premises. This may result in an unmetered supply arrangement at this site. This fee will also be levied where a metering provider has requested the distributor to check a potentially faulty network connection and when tested by the distributor, no fault is found.	Alternative control	Alternative control (specific monopoly service)
Meter recovery and disposal − type 5 and 6 (legacy meters)	Activities include: • at the request of the customer or their agent to remove and dispose of type 5 or 6 current transformer (CT) meters where a permanent disconnection has been requested. • disposing of type 5 or 6 whole current (WC) meters which may otherwise be removed and disposed of by the	N/A	Alternative control (specific monopoly service)

Service group/Activities included in service group	Further description	Current Classification 2017−19	Proposed classification 2019−24
	incoming metering provider.		
Distributor arranged outage for purposes of replacing metering	At the request of a retailer or metering coordinator provide notification to affected customers and facilitate the disconnection/reconnection of customer metering installations where a retailer planned interruption cannot be conducted.	N/A	Alternative control (specific monopoly service)
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 the rules).	N/A	Alternative control (specific monopoly service)
Legacy pre-payment meters	The operation and maintenance of legacy pre-payment meters and associated services, for pre-payment meters as a specific service for retailers.	N/A	Alternative control (specific monopoly service)
Connection services			
Premises connection services and extensions	Premises connection services includes any additions or upgrades (including design and construction) to the connection assets located on the customer's premises (Note: excludes all metering services). Extension is 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.	Alternative control	Alternative control
Augmentations	Any shared network enlargement/enhancement undertaken by a distributor which is not an extension.	Standard control	Standard control

Service group/Activities included in service group	Further description	Current Classification 2017−19	Proposed classification 2019−24
Reconnections/Disconnections	Disconnection and/or reconnection services (some provided in accordance with the National Energy Retail Rules). Examples include (but are not limited to): • Disconnection visit (site visit only) • Disconnection visit (disconnection completed - technical) • Disconnection visit (disconnection completed) • 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.	Alternative control	Alternative control (specific monopoly service)
Public lighting			
Public lighting	Provision, construction and maintenance of public lighting and new/emerging public lighting technology services.	Alternative control (existing public lighting services Negotiated (new public lighting technology)	Alternative control

Service group/Activities included in service group	Further description	Current Classification 2017−19	Proposed classification 2019−24
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
Contestable metering support roles	Includes metering coordinator (except where the distributor is the initial metering coordinator), metering data provider and metering provider for meters installed or replaced after 1 December 2017.	N/A	Unclassified distribution service
Provision of training to third parties for non-network related issues	Training programs provided to third for non-network related issues	N/A	Unclassified distribution service
Non-distribution services – Although this table relates to distribution services, we have included the below non-distribution services for clarity.			
Operation and maintenance of isolated distribution networks not part of the NEM	The operation and maintenance of third party owned distribution networks not physically connector to the distributor's distribution network. E.g. TasNetworks and Hydro Tas.	N/A	Non-distribution service