Preliminary positions on replacement framework and approach (for consultation)

for

TasNetworks Distribution

for the

Regulatory control period commencing 1 July 2017

AUSTRALIAN ENERGY REGULATOR

April 2015

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AER reference: 56853

Decision to replace framework & approach

On 27 February 2015 we issued a notice under the Rules,[1] inviting submissions on whether it is necessary or desirable to amend or replace the current Framework & Approach (F&A) for Tasmania. Submissions closed on 18 March 2015 and we received six responses.[2]

We consider it necessary to replace the Tasmanian F&A due to the extent of the issues with the current F&A.[3] We consider issues which need to be reviewed are:

- the classification of public lighting services in light of submissions received from Hobart City Council, Glenorchy City Council, Trans Tasman Energy Group and a request from TasNetworks to review the current classification of these services
- the application of our service target performance incentive scheme in light of a request from TasNetworks to review the revenue at risk applied under the scheme
- the need to include formulae that give effect to the control mechanisms (that is, how price and/or revenues are to be determined during the regulatory control period)
- the need to outline the application of our revised efficiency benefit sharing scheme
- the likely inclusion of a capital expenditure sharing scheme (to incentivise network service providers to undertake efficient capital expenditure)
- the possible inclusion of a small-scale incentive scheme (pilot or test incentive schemes within an environment that limits the sum of money at risk and the length of time of the scheme)
- the application of the Expenditure Forecast Assessment Guidelines (a nationally consistent reporting framework which allows us to compare the relative efficiencies of network service providers, and decide upon efficient expenditure allowances)

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1 NER, cl. 6.8.1(a)(2).

2 Responses are available at www.aer.gov.au/node/30748.

3 AER, *Framework and approach paper for Aurora Energy Pty Ltd, Regulatory control period commencing 1 July 2012*, 29 November 2010.

- whether depreciation for establishing the network service providers opening regulatory asset base for the 2022–2027 regulatory control period is to be based on actual or forecast depreciation.[4]

The remainder of this paper sets out—for discussion—our preliminary positions on a replacement F&A for these issues and for other matters to be addressed in the F&A.

4 NER, cl. 6.8.1(b)(2).

Request for submissions

Interested parties are invited to make written submissions to the Australian Energy Regulator (AER) regarding this paper by the close of business, 15 May 2015.

Submissions should be sent electronically to: TASelectricity2017@aer.gov.au

Alternatively, submissions can be mailed to:

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Melbourne VIC 3000

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

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

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

Enquiries about this paper, or about lodging submissions, should be directed to the Networks Branch of the AER on (03) 9290 1426.

Contents

About the framework and approach

The Australian Energy Regulator (AER) is the economic regulator for transmission and distribution services in Australia's national electricity market (NEM).[5] We are an independent statutory authority, funded by the Australian Government. Our powers and functions are set out in the National Electricity Law (NEL) and National Electricity Rules (the rules or NER).

The preliminary positions paper for the framework and approach (F&A) is the first step in a process to determine efficient prices for electricity distribution services. This paper sets out our preliminary positions on which services we will regulate and how we propose to apply the relevant incentive schemes. It also facilitates early public consultation and assists network service providers to prepare regulatory proposals.

TasNetworks Distribution (formerly Aurora Energy) is a licensed regulated operator of the Tasmanian monopoly electricity distribution network. The network comprises the poles, wires and transformers used for transporting electricity across urban and rural population centres to homes and businesses. TasNetworks Distribution (TasNetworks) designs, constructs, operates and maintains the distribution network for Tasmanian electricity consumers.

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

We have decided to replace the current Tasmanian F&A for the next regulatory control period. This decision arose following consultation with stakeholders.[6] Our main reason for this decision was because of significant changes to the rules, making elements of the current F&A no longer relevant. TasNetworks has sought a new or amended F&A. Submissions received also supported the amendment or replacement of the current F&A. The AER's Consumer Challenge Panel submitted that there has been sufficient change to the physical

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

6 NER, clauses 6.8.1(c)(1)–(3).

and regulatory environments in which TasNetworks operates to warrant a review of the F&A.[7] Copies of all submissions are available at http://www.aer.gov.au/node/30748.

The current five year Tasmanian distribution regulatory control period concludes on 30 June 2017. This paper relates to the regulatory control period commencing 1 July 2017 and sets out our preliminary positions on:

- distribution service classification (which services are to be regulated)
- control mechanisms (how will prices be determined) and the formulae that give effect to the control mechanisms
- service target performance incentive scheme
- efficiency benefit sharing scheme
- capital expenditure sharing scheme
- demand management incentive scheme
- application of the expenditure forecast assessment guidelines
- whether depreciation will be based on forecast or actual capital expenditure
- jurisdictional and legacy issues.

We will use the F&A process to commence discussions with TasNetworks about the treatment of confidential information as set out in our confidentiality guideline.[8] We encourage TasNetworks to also consult consumers, as part of its consumer engagement, to gain a better understanding of the type of information consumers are interested in accessing.[9]

Following release of this paper, we will consult with interested parties before issuing our final F&A by 31 July 2015. Table 1 summarises the Tasmanian distribution determination process.

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[7] Consumer Challenge Panel - Sub Panel CCP4, Submission, 10 March 2015.

[8] AER, *Confidentiality guideline*, 19 November 2013.

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

Table 1: Tasmanian distribution determination process

Step	Date
AER publishes preliminary positions F&A for TasNetworks	2 April 2015
AER to publish final F&A for TasNetworks	31 July 2015
TasNetworks submits regulatory proposal to AER	31 January 2016
Submissions on regulatory proposal close	May 2016
AER to publish draft decision	30 September 2016
TasNetworks to submit revised regulatory proposal to AER	December 2016
Submissions on revised regulatory proposal and draft decision close	January 2017*
AER to publish distribution determination for regulatory control period	30 April 2017

* 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, 11, Part E.

Overview

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

- classification of distribution services (which services we will regulate)
- control mechanisms (how we will determine prices for regulated services) and the formulae that give effect to the control mechanisms
- the application of a range of incentives schemes that encourage desired behaviours such as improvements in service quality or efficient capital and operating expenditure
- the application of a range of expenditure forecasting expenditure tools used to test TasNetworks' regulatory proposal
- how we will calculate depreciation of TasNetworks' regulatory asset base going forward.

Classification of distribution services

Classification is important to electricity customers because it determines the need for and scope of regulation applied to distribution services central to electricity supply. Distribution services include, for example, the provision and maintenance of poles and wires and connection or disconnection to electricity. When we classify distribution services we determine the nature of the economic regulation we will apply to those services.

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

Our preliminary view is that the classification of TasNetworks' distribution services will not change for the 2017–22 regulatory control period. The majority of services provided by TasNetworks relate to building and maintaining the network and these will remain standard control services. Similarly, we propose public lighting (excluding new public lighting technology services), metering and ancillary network (fee based and quoted) services remain as alternative control services.

Our Tasmanian distribution service classifications represent our preliminary position for the next regulatory control period. Table 2 provides an overview of the different classes of distribution services for the purposes of economic regulation under the rules.

Table 2: Classifications of distribution services

Classification		**Description**	**Regulatory treatment**
Direct control service	Standard control service	Services that are central to electricity supply and therefore relied on by most (if not all) customers such as building and maintaining the shared distribution network. Most distribution services are classified as standard control.	We regulate these services by determining prices or an overall cap on the amount of revenue that may be earned for all standard control services. The costs associated with these services are shared by all customers via their regular electricity bill.
	Alternative control service	Customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by the local distributor.	We set service specific prices to enable the distributor to recover the full cost of each service from customers using that service.
Negotiated service		Services we consider require a less prescriptive regulatory approach because all relevant parties have sufficient countervailing market power to negotiate the provision of those services.	Distributors and customers are able to negotiate prices according to a framework established by the rules. We are available to arbitrate if necessary.
Unclassified service		Services that are not distribution services[10] or services that are contestable.	We have no role in regulating these services.

Source: AER

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

Direct control services

The rules contain factors we must consider when determining appropriate levels of economic regulation for the range of electricity distribution services. Following consideration of those factors, we may determine that a prescriptive approach is required. We will classify such services as direct control services. That is, we will directly set prices distributors will charge customers, or set revenues distributors may recover from customers.[11]

Most distribution services fall within the network services group, which includes poles, wires, and other core infrastructure of a distribution business.[12] These are central to a distributor's business and the broad customer base uses them. Network services are central to a distributor's monopoly power and are frequently subject to licence restrictions. Therefore, our preliminary position is to classify network services as direct control services. Other distribution services are also subject to limited, or no, competition. We therefore also propose to classify as direct control: metering, connections, public lighting and ancillary network services. We must further determine whether we will classify a direct control service as a standard control or alternative control service.

Standard control services

We classify as standard control services those distribution services that are central to electricity supply and therefore relied on by most (if not all) customers. We classify most distribution services as standard control, reflecting the integrated nature of an electricity distribution system. We typically regulate these services by determining prices or an overall cap on the amount of revenue that distributors may earn for all standard control services. These standard control services form the core distribution component of an electricity bill.

Our preliminary position is that standard control services include network services and connection services. These services encompass construction, maintenance and repair of the network, customer connection and augmenting the network to facilitate connecting new customers.

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

12 Appendix B sets out TasNetworks' distribution services in more detail.

Alternative control services

Alternative control services are customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by a single distributor. Alternatively, certain customers may request these services. For these services, we set service specific prices to enable the distributor to recover the full cost of each service from customers using that service. We will determine prices for individual alternative control services in a variety of ways, suitable to specific circumstances. For example, only a few customers purchase ancillary network services (like a request to relocate a power pole). It would be inefficient for all customers to fund provision of these services.

We propose to retain the current alternative control classification for type 5-7 metering services and ancillary (quoted and fee based) network services.

We also propose to retain the current alternative control classification for public lighting, because a defined group of customers purchase these services, for example, local councils. We would be interested in feedback on whether we should classify public lighting differently.

Negotiated distribution services

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

Our preliminary position is to continue to classify services to install new public lighting technologies as negotiated distribution services. We are interested in stakeholder feedback on whether we could classify all public lighting services as negotiated services.

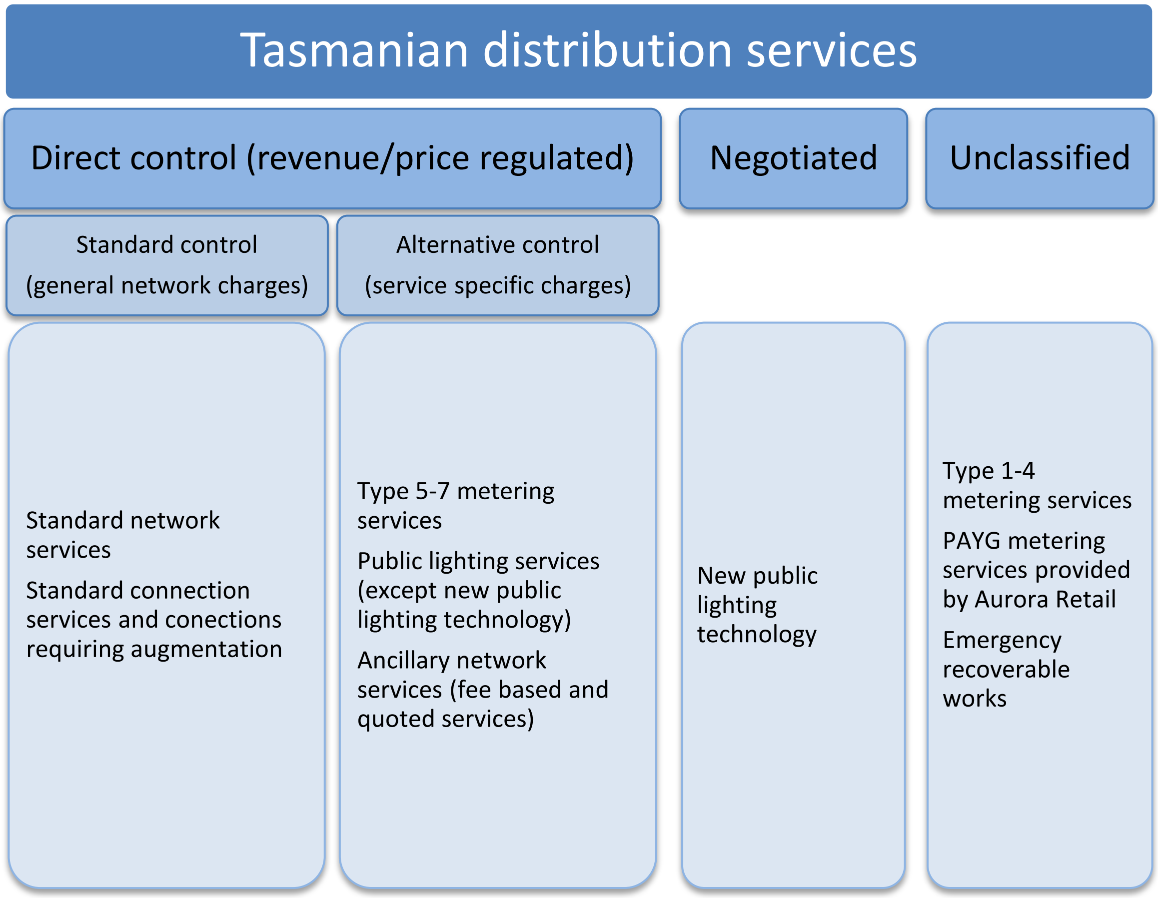
Unclassified (unregulated)

In the case of some distribution services, we may determine there is sufficient competition for no regulation at all. We will not classify such services. We refer to these as unclassified or unregulated distribution services.

Our preliminary position is to not classify emergency recoverable works.[13] This will create the right incentives for distributors to recover the cost of emergency recoverable works from third parties that caused damage to the network. Pay as you go (PAYG) metering services provided by Aurora Retail are distinct from the metering services provided by TasNetworks Distribution. PAYG metering services provided by Aurora Retail are also unclassified and not regulated by the AER.[14]

We use the above service classifications throughout this preliminary position F&A. Figure 1 sets out our preliminary positions for classification of Tasmanian distribution services.

Figure 1: AER proposed approach to classification of Tasmanian distribution services



Source: AER

[13] Emergency recoverable works are services related to repairing the distribution network after damage to restore or maintain electricity supply.

[14] The Consumer Challenge Panel's (CCP4) submission requested clarification of the classification of PAYG metering services. Consumer Challenge Panel - Sub Panel CCP4, Submission, 10 March 2015.

Control mechanisms

Following on from service classifications, our determinations must impose controls on direct control service prices and/or their revenues.[15] We may only accept or approve control mechanisms in a distributor's regulatory proposal if they are consistent with our final F&A.[16]

The rules require us to decide the control mechanism forms[17] and the formulae to give effect to the control mechanism, but not the basis of the form of control mechanism. In deciding control mechanism forms, we must select one or more from those listed in the rules.[18] These include price schedules, caps on the prices of individual services, weighted average price caps, revenue caps, average revenue caps and hybrid control mechanisms.

In deciding on the form of control mechanism, the rules require us to have regard to specified factors.[19] These include the need for efficient tariffs, administrative costs, previous regulatory arrangements and consistency. In light of the above alternatives and considerations, our preliminary position on the form of control mechanisms for TasNetworks are:

- standard control services— revenue cap

  We consider that a revenue cap best meets the factors set out under clause 6.2.5(c) of the rules. We consider that a revenue cap will result in benefits to consumers through a higher likelihood of revenue recovery at efficient cost, better incentives for demand side management, less reliance on energy forecasts and further alignment with the development of efficient prices. Furthermore, we consider that the detriments of a revenue cap – within period pricing instability and weak pricing incentives are able to be mitigated.

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

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15 NER, clause 6.2.5(a).

16 NER, clause 6.12.3(c).

17 NER, clause 6.2.5(b).

18 NER, clause 6.2.5(b).

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

For standard control services, the rules mandate the basis of the control mechanism must be the prospective CPI–X form, or some incentive-based variant.[20] For alternative control services, we will confirm a control mechanism basis through the distribution determination process.

Incentive schemes

The purpose of incentive schemes is to encourage distributors to manage their businesses in a safe, reliable manner that serves the long term interests of consumers. The schemes provide distributors with incentives to only incur efficient costs and to meet or exceed service quality targets. In some instances, distributors may incur a financial penalty if they fail to meet set targets. These schemes include the service target performance incentive scheme, efficiency benefit sharing scheme, capital expenditure sharing scheme and demand management incentive scheme. The overall objectives of the schemes are to:[21]

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

We outline below our preliminary position on the application of each scheme to TasNetworks.

Service target performance incentive scheme

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

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

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

Our preliminary position is to continue to apply the national STPIS to TasNetworks in the next regulatory control period. We will not apply the guaranteed service level (GSL) component as TasNetworks is subject to a jurisdictional GSL scheme.[22] Should the Tasmanian Government remove this obligation before the next regulatory control period commences, we will apply the GSL component of the STPIS.

Efficiency benefit sharing scheme

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

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

Capital expenditure sharing scheme

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

As part of our Better Regulation program we consulted on and published version 1 of the capital expenditure incentive guideline for electricity network service providers (capex incentive guideline) which sets out the CESS. Our preliminary position is to apply the CESS to TasNetworks for the next regulatory control period.

Demand management incentive scheme

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

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[22] OTTER, *Guideline - Guaranteed Service Level Scheme*, December 2007..

Our preliminary position is to continue to apply the DMIS to TasNetworks for the next regulatory control period. The DMIS adds an innovation allowance to TasNetworks' revenue each year of the regulatory control period. In calculating the allowance, we must have regard to a range of factors around benefits to consumers and how the DMIS balances against other incentive schemes.

The AEMC is currently consulting on rule change requests from the Total Environment Centre (TEC) and the Council of Australian Governments' Energy Council (COAG Energy Council) regarding reform of the DMIS under Chapter 6 of the NER.[23] The requests are in response to recommendations made by the AEMC in its Power of Choice review.[24] We intend to develop and implement a new DMIS during the next regulatory control period, depending on the progress of the rule change process.

Small-scale incentive scheme

The rules state that we may develop a small-scale incentive scheme.[25] We have not developed this scheme. Therefore, we will not be stating our preliminary position on the application of this scheme to TasNetworks.

Application of the expenditure forecast assessment guideline

In 2014 we published our expenditure forecast assessment guideline (expenditure assessment guideline). The expenditure assessment guideline is based on a nationally consistent reporting framework allowing us to compare the relative efficiencies of distributors and decide on efficient expenditure allowances. Our preliminary position is to apply the guideline, including the information requirements to TasNetworks in the next regulatory control period.

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

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23 AEMC, *Consultation paper, National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, 19 February 2015.

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

25 NER, clause 6.6.4.

Depreciation

Changes to the rules require us to state our approach to calculating depreciation when we roll forward TasNetworks' regulatory asset base (RAB) for the 2022–2027 regulatory control period. Our preliminary position is to use forecast depreciation to establish the RAB as at 1 July 2022.

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

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

Jurisdictional and legacy issues

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, our preliminary position is that we are not required to, and will not; make any determination under the rules regarding dual-function assets.[26]

Regulatory control period

TasNetworks is proposing to align the regulatory control periods of its distribution and transmission businesses through implementation of a two year regulatory control period for its distribution business

[26] NER, clauses 6.8.1(b)(1)(ii) and 6.25(b).

instead of the five year period currently required by the rules.[27] TasNetworks has proposed a rule change to allow a two year regulatory control period commencing on 1 July 2017 and ending on 30 June 2019 for its distribution business.

The AEMC is assessing this rule change request as a non-controversial rule under its expedited rule making process and, subject to any submissions objecting to an expedited process, will publish a final rule determination by 9 April 2015.

The AER has not objected to TasNetworks' rule change request. Subject to the outcome of this request we will give consideration to the impact of a shorter regulatory control period for incentives for efficient expenditure, the operation of incentive schemes, the next F&A process and any other relevant matters.

[27] NER, clause 6.3.2(b).

1 Classification of distribution services

This attachment sets out our preliminary position on the classification of distribution services provided by TasNetworks in the next regulatory control period. Service classification determines the nature of economic regulation, if any, applicable to specific distribution services. Classification therefore determines whether we:

- directly control prices[28]
- allow parties to negotiate services and prices and only arbitrate disputes if necessary, or
- do not regulate at all.

If we control prices directly, classification further determines whether distributors recover service costs from all customers or only those benefiting directly from specific services.[29]

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

The preliminary positions set out in this attachment are not binding on us or TasNetworks. That is, we will consider alternative proposals submitted in response to this preliminary F&A by TasNetworks or other interested parties. Taking into account submissions received, we will publish our final classification decisions

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

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

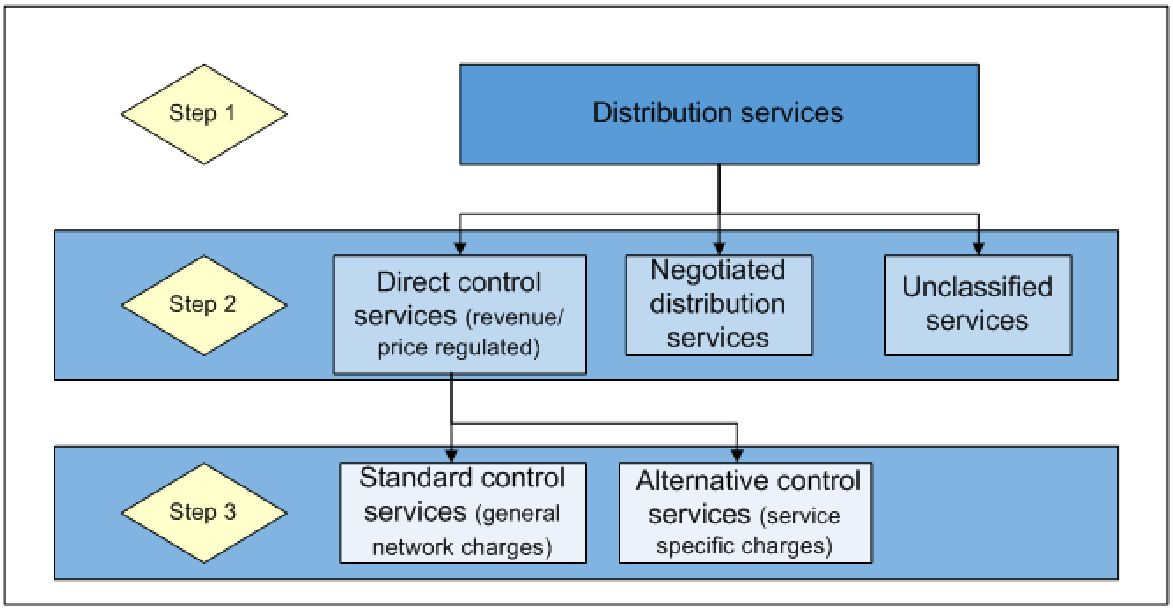
in a final F&A. Once we have published our F&A paper, we may only change our classification decisions in response to unforeseen circumstances.[30]

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

As illustrated by figure 2:

- We must first satisfy ourselves that a service is a 'distribution service' (step 1). The rules define a distribution service, as a service provided by means of, or in connection with, a distribution system.[31] 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'.[32]

Figure 2: Distribution service classification process



Source: NER, chapter 6, part B.

- We then consider whether economic regulation of the service is necessary (step 2). When we do not think economic regulation is warranted we will not classify the service. If economic regulation is

30 NER, clause 6.12.3(b).

31 NER, chapter 10, glossary.

32 NER, chapter 10, glossary.

necessary, we consider whether to classify the service as either a direct control or negotiated distribution service.

- When we think we should classify a service as direct control, we further classify it as either a standard control or alternative control service (step 3).

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

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

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

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

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

1.1 AER's preliminary position

Before considering how to classify services, we consider how to group them. This allows a more straightforward approach to classification, as our classification decisions for a group of services relates to each service within the group. Our preliminary position is to group distribution services provided by TasNetworks as:

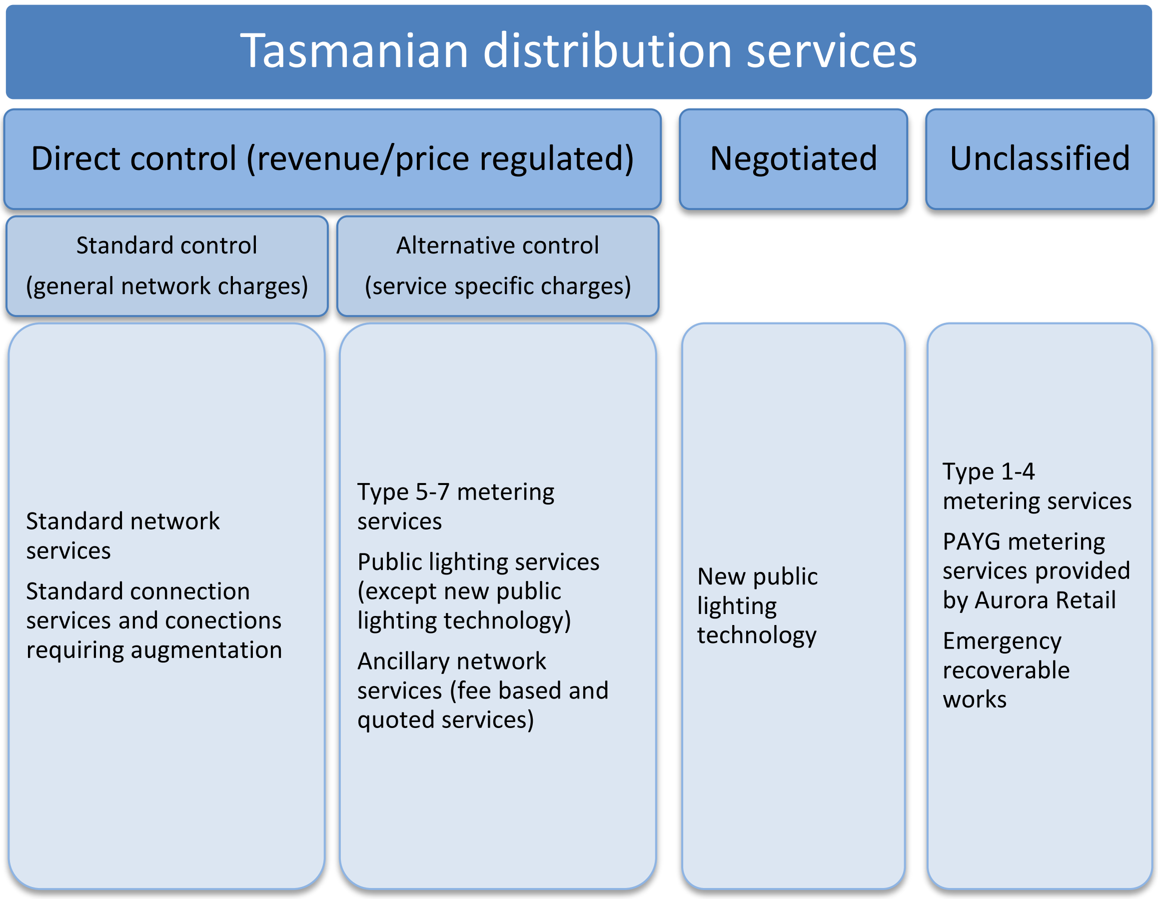
- network services

- metering services

- public lighting services
- connection services
- ancillary network services (fee based and quoted services).

We consider each service falling within the above service groups is a distribution service.[33] They are services provided by means of, or in connection with, a distribution service.[34] Figure 3 summarises our preliminary classification of TasNetworks' distribution services. The following section summarises our preliminary positions on the classification of each service group.

Figure 3: AER proposed approach to classification of Tasmanian distribution services



Source: AER

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

[34] NER, chapter 10, 'distribution system'.

1.1.1 Network services

Most distribution services supplied by TasNetworks fall within the network services group. Network services are at the core of what an electricity distributor does, and include constructing and maintaining those parts of the electricity network that everyone uses—that is, the shared distribution network. The relatively high fixed costs of providing network services mean that it would be inefficient to have more than one network in the same geographic location. Competition in the provision of network services would not be in the interests of customers because electricity prices would have to be higher, reflecting the higher costs of having to build and maintain more than one distribution network. As competition is absent, we apply the most prescriptive form of regulation to network services—direct control.

TasNetworks' customers use network services through a shared network, provided under monopolistic conditions. Therefore, we classify network services as standard control services so that TasNetworks can recover the cost of providing network services from across its broad customer base. The lack of competition in the provision of network services gives further weight to classifying network services as standard control services.

1.1.2 Metering services

TasNetworks is the monopoly supplier of type 5, 6 and 7 metering services in Tasmania and we currently classify these as alternative control services. The classification reflects the limited prospect of competition in the supply of type 5-7 metering services to date and that their cost can be directly attributed to individual customers. In contrast the supply type 1-4 metering services are contestable and we do not currently regulate these services—they are unclassified. We propose to retain the current approach to classification of type 5-7 and type 1-4 metering services.[35]

35 Pay as you go (PAYG) metering services provided by Aurora Retail are distinct from the metering services provided by TasNetworks Distribution. PAYG metering services provided by Aurora Retail are unclassified and not regulated by the AER.

Proposed rule changes currently under consideration by the AEMC would facilitate the competitive provision of metering and related services in the future.[36] The AEMC's consultation on the proposed rule changes is currently underway and a final determination is expected in mid-2015.

The AER may revise its position on classification of metering services in Tasmania if this is necessary to achieve a position consistent with the approach to metering regulation in forthcoming determinations for distributors in NSW, Queensland and South Australia and the rule changes ultimately adopted. This is discussed in more detail below.

1.1.3 Public lighting services

Public lighting repair, maintenance, like-for-like replacement and the provision of new public lighting assets are currently alternative control services in Tasmania. Installation of new public lighting technologies is currently a negotiated service. These classifications reflect that public lighting services have generally been provided as monopoly services by TasNetworks to specific customers—usually local government councils—while the emergence of new lighting technologies and providers is increasing the potential for alternative supply arrangements.

While our preliminary position is to retain the current classifications, we are seeking views on whether there is a basis for reclassifying these services. TasNetworks has requested that a change to the classification of public lighting services be considered. We also received submissions supporting this view. This is discussed in more detail below.

1.1.4 Connection services

Connection services involve connecting new customers to the shared network. In Tasmania, these services can only be supplied by TasNetworks and we currently classify standard connection services and connections requiring augmentation as standard control services. The cost of connection services is therefore spread across all customers using the shared network excluding the cost of any up-front capital contributions made by customers requesting connection services.

[36] See http: www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv.

Our preliminary position is to retain the current standard control services classification for connection services.

1.1.5 Fee based services (ancillary network services)

Fee based services are provided on request for the benefit of a single customer. These services tend to be homogeneous in nature and scope, and can be costed in advance of supply with reasonable certainty. TasNetworks is the sole provider of a range of fee based services relating to its distribution network (e.g. energisation, de-energisation, re-energisation, meter testing, meter alteration) which are supplied under scheduled prices. Our preliminary position is to retain the current alternative control service classification for fee based services.

For classification purposes, we propose to replace the current service groups called 'fee-based services' with a service group called 'ancillary network services'.

1.1.6 Quoted services (ancillary network services)

Quoted services are non-standard services provided on request for the benefit of a single customer. These services tend to be dissimilar in nature and scope, and cannot be costed in advance of supply with reasonable certainty. TasNetworks is the sole provider of a range of quoted services relating to its distribution network (e.g. moving mains, services or meters, temporary supply, alteration and relocation of existing public lighting assets) which are supplied under scheduled labour charge-out rates with allowance for materials and other costs.

For classification purposes, we propose to replace the current service groups called 'quoted services' with a service group called 'ancillary network services'.

1.2 AER's assessment approach

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

When deciding whether to classify services as either direct control or negotiated services, or to not classify them, the rules require us to have regard to the 'form of regulation factors' set out in the NEL.[37] We have reproduced these at appendix A. They include the presence or extent of barriers to entry by alternative providers and whether distributors possess market power in provision of the services. The rules also require us to consider the previous form of regulation applied to services and the desirability of consistency with the previous approach.[38]

For services we intend to classify as direct control services, the rules require us to have regard to a further range of factors.[39] These include the potential to develop competition in provision of a service and how our classification may influence that potential. Also, whether the costs of providing the service are attributable to a specific person. And, the possible effect of the classification on administrative costs.

The rules also specify that for a service regulated previously, unless a different classification is clearly more appropriate, we must:[40]

- 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.[41]

1.3 Reasons for AER's preliminary position

This section sets out our preliminary position and reasons for the classifications we propose for:

- network services
- metering services
- public lighting services

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37 NER, clause 6.2.1(c); NEL, s. 2F.

38 NER, clause 6.2.1(c).

39 NER, clause 6.2.2(c).

40 NER, clause 6.2.2(d).

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

- connection services
- ancillary network services (fee based and quoted services).

1.3.1 Network services

Distributors provide network services over a shared distribution network to all customers connected to it. Network services are associated with safe and reliable electricity supply.[42] Customers use or rely on network services on a daily basis. Examples include the construction and maintenance of the shared network.

Our preliminary position is to classify network services as direct control services and further, as standard control services. We also propose not to classify emergency recoverable works, even though they are similar to network services.

TasNetworks holds an electricity distribution licence which is the only distribution license that is currently in place for mainland Tasmania. The AER notes that under section 17 of the *Electricity Supply Industry Act 1995* (ESI Act), a person is prevented from distributing and supplying electricity unless they hold a licence authorising them to do so. These arrangements provide a regulatory barrier, preventing third parties from providing network services.[43] Therefore, we consider that there is no market for network services for third parties to compete in.

TasNetworks possesses significant market power due to the regulatory arrangements in place.[44] As such, we intend to classify network services as direct control services.

We must further classify direct control services as either standard or alternative control services.[45] Our preliminary position is to retain the current standard control classification for network services. There is little, if any, potential to develop competition in the market for network services.[46] There would be no material effect on administrative costs for us, TasNetworks, users or potential users.[47] This is because classifying

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[42] NER, chapter 10, definition of 'network service'.

[43] This is relevant under the form of regulation factors; see NEL, s. 2F(a).

[44] This is a relevant form of regulation factor: NEL, s. 2F(d).

[45] NER, clause 6.2.2(c).

[46] NER, clause 6.2.2(c)(1).

[47] NER, clause 6.2.2(c)(2).

network services as standard control services is consistent with the current regulatory approach. We currently classify network services in Tasmania and all other NEM jurisdictions as standard control services.[48] Further, distributors provide network services through a shared network and therefore cannot directly attribute the costs of these services to individual customers.[49]

Emergency recoverable works

Emergency works relate to repairing the distribution network after damage to restore or maintain electricity supply. For example, damage caused by a storm. Emergency *recoverable* works relate to 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. We currently classify TasNetworks' distribution emergency recoverable works as standard control services.[50]

Distributors carry out emergency recoverable works as part of the normal maintenance and repair to the network to ensure the safe and reliable supply of electricity. Only a distributor may perform these types of repairs on its assets and this creates a monopoly.

Given that these services are provided in connection with a distribution system, we consider emergency recoverable works are a distribution service. However, in terms of classification, we consider that emergency recoverable works are distinguishable from other network services. This is because the cost of these works may be recovered under common law. That is, the distributor can seek payment of their costs to fix the network from the parties responsible for causing the damage, through the courts if necessary.

For this reason, we intend not to classify emergency recoverable works.[51] By not classifying emergency recoverable works, TasNetworks is not able to recover costs for these services from consumers as a whole. Rather, to be compensated for damage to the network caused by an identifiable party, TasNetworks must seek to recover costs from that party. We consider this will establish the right incentives for TasNetworks to pursue costs from parties responsible for damage to distribution network assets. Our preliminary approach

48 NER, clause 6.2.2(c)(3).

49 NER, clause 6.2.2(c)(5).

50 Emergency recoverable works are a component of TasNetworks' 'emergency response' services.

51 NER, clause 6.2.1(c)(4).

to this issue is consistent with our approach to the classification of emergency recoverable works in NSW, Queensland[52] and Victoria.[53]

1.3.2 Metering services

All electricity customers have a meter that measures the amount of electricity they use.[54] However, not all customers have the same type of meter. There are different types of meters, measuring electricity usage in different ways. The metering installation types are defined in schedule 7.2 of the NER.

Large customers use type 1 to 4 meters which provide a range of additional functions compared to other meters. In particular, these meter types have a remote communication ability. Type 1 to 4 meters are competitively available and we do not currently regulate them in Tasmania or in most other jurisdictions—they are unclassified.

Type 5 metering is defined in the NER as a manually read interval meter whilst type 6 is a manually read accumulation meter. TasNetworks is the monopoly providers of type 5 (interval) and 6 (accumulation) meters.[55] Type 6 meters record total electricity usage over a period of time. Type 5 meters can record electricity usage and time of use.[56] Households and other small customers traditionally use these meter types. These meters are manually read.

Type 7 metering services are unmetered connections with a predictable energy consumption pattern (for example, public lighting connections).[57] Such connections do not include a meter that measures electricity use. Rather, electricity use by these connections is estimated. 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 Tasmania.

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52 NER, clause 6.2.1(c)(4). Also, AER, *Stage 1 Framework and approach paper – Ausgrid, Endeavour Energy and Essential Energy*, March 2013, p. 20.

53 AER, *Final Framework and approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016*, October 2014.

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

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

56 Interval meters record electricity usage every 30 minutes.

57 NER, clause 7.2.3(a)(2).

Special meter readings and meter testing of type 5, 6 and 7 meters cover a range of other metering related services which TasNetworks supplies as a monopoly to specific customers.

As discussed below we propose to retain the current approach to classification of type 5-7 and type 1-4 metering services.

Type 5 to 7 metering services

TasNetworks is the monopoly provider of existing type 5, 6 and 7 metering services and consequently we intend to classify these services as direct control.[58] We think contestability in special meter readings and meter testing services for type 5, 6 and 7 meters is also limited by the monopoly nature of TasNetworks' type 5-7 metering services, for which meter reading and testing services are undertaken.[59] For this reason, we propose to also classify special meter readings and meter testing services for type 5, 6 and 7 meters as direct control services.

These services are currently classified as alternative control which reflects that there has been limited prospect of competition in the supply of type 5-7 metering, special meter readings and meter testing services, and that their cost can be directly attributed to individual customers. Our preliminary position is that a different classification of these metering services is not clearly more appropriate[60] and we propose to maintain the current alternative control classification.

Type 1 to 4 metering services

Type 1 to 4 metering services are contestable in Tasmania and competitively available.[61] For this reason, our preliminary position is not to classify these services. This is consistent with the current regulatory approach in Tasmania and in most other jurisdictions.[62]

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58 NER, clause 6.2.1.

59 NEL, s. 2F(a) and (d).

60 NER, clause 6.2.2(d).

61 Industrial and large customers may use types 1, 2, 3 or 4 meters. These meters are already open to competition and are not regulated by us (NER, clauses 7.2.3(a)(2) and 7.3.1.A(a)).

Expanding competition in metering and related services

In October 2013 the Standing Council on Energy and Resources (SCER) (now the COAG Energy Council) submitted a rule change request seeking to establish arrangements that would promote competition in the provision of metering and related services in the NEM. SCER proposed changes to the NER, and National Energy Retail Rules where necessary, to implement arrangements that would support a competitive market for the provision of metering and related services.

The proposed changes are largely based on the recommendations made by the AEMC in its Power of Choice review in 2012. The proposed changes form part of SCER's (now COAG Energy Council's) broader energy market agenda to support investment and market outcomes in the long term interests of consumers. The AEMC recommended metering costs be unbundled from shared network charges.[63] Also, that provision of metering services be contestable and not be a monopoly service exclusively provided by distributors. The AEMC is currently considering this rule change.

Vector Limited has submitted that contestability in metering services be considered in the development of the F&A for Tasmania. Vector Limited stated:

> Ongoing reforms include the introduction of competition in metering services in the National Electricity Market ("NEM"). This would have significant implications for Tasmania, where type 5 and type 6 ("legacy") metering services are currently being provided only by TasNetworks.
>
> TasNetworks' existing F&A paper has envisaged no alternative metering providers entering the market (during the current regulatory control period), i.e. that metering services will continue to be provided only by TasNetworks (then Aurora Energy):
>
> ... This assumption needs to be revised in TasNetworks' existing F&A paper, given that one of the intentions of the ongoing reforms is to open up the metering market to competition.[64]

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62 NER, clause 6.2.2(c)(3) and (4). Also, AER, *Stage 1 Framework and approach paper – Ausgrid, Endeavour Energy and Essential Energy*, March 2013, p. 26. AER, *Final Framework and approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016*, October 2014.

63 AEMC, Power of choice review – giving consumers options in the way they use electricity – final report, November 2012, p. 83.

64 Vector Limited, Submission, 18 March 2015.

While we do not determine the contestability of metering services through our F&A process, our preliminary approach to classification would facilitate contestability should rule and other changes occur to open up the metering market in Tasmania.

As set out above, we propose to classify type 5, 6 and 7 metering services as alternative control, maintaining the current separation between the costs for these services and network services. Our preliminary approach is therefore consistent with the AEMC's final report for its Power of Choice Review[65] and SCER's subsequent rule change request which promote the unbundling of metering costs and services from network services.[66]

As noted by Vector Limited in its submission,[67] there are a number of issues currently under consideration associated with effective implementation of contestability in metering services, such as cost recovery for an existing meter owned by a distributor where customers acquire a new meter from an alternative supplier. The AER will be giving consideration to these issues in forthcoming determinations for distributors in NSW, Queensland and South Australia. There is a clear intent of policy makers to see a competitive metering market develop in the NEM and we recognise that exit fees represent a significant barrier to this market. We have sought to reduce this barrier by classifying metering services, as alternative control services, in a way that allows for the recovery of the distributor's sunk residual capital costs of a meter from all customers.

It is noted that the AEMC's consultation on the proposed rule changes referred to above is currently underway and a final determination is expected in mid-2015.[68] The AER may revise its position on classification of metering services in Tasmania if this is necessary to achieve a position consistent with the approach to metering regulation in forthcoming determinations for distributors in NSW, Queensland and South Australia and the rule changes ultimately adopted.

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65 AEMC, *Power of choice review – giving consumers options in the way they use electricity – final report*, November 2012, chapter 4.

66 SCER, *Introducing a new framework in the National Electricity Rules that provides for increased competition in metering and related services, rule change request*, SCER, October 2013, p 11.

67 Vector Limited, Submission, 18 March 2015.

68 See: http: www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv.

1.3.3 Public lighting

TasNetworks operates and maintains the public lighting system throughout Tasmania on behalf of 29 local councils and the Department of State Growth. While the Department is responsible for providing public lighting on state roads and major highways, these assets are serviced and maintained by TasNetworks. TasNetworks owns the majority of public lighting assets in Tasmania where approximately 75 per cent of public lights are supported on TasNetworks' electricity distribution poles. The remaining 25 per cent are supported by dedicated public lighting poles which are mostly privately owned.[69] The provision of new public lighting services, such as the design, construction and connection of public lighting assets, has previously been undertaken by TasNetworks in the majority of new estate developments. Estate developers have also undertaken design and construction public lighting assets, later transferring ownership of these assets to local councils or TasNetworks. Prior to the current regulatory control period, public lighting services were not regulated in Tasmania.

Public lighting repair, maintenance, like-for-like replacement and the provision of new public lighting assets are currently alternative control services in Tasmania. Installation of new public lighting technologies is currently a negotiated service. These classifications reflect that public lighting services have generally been provided as monopoly services by TasNetworks to specific customers while the emergence of new lighting technologies has increased the potential and demand for alternative supply arrangements.

New technologies are producing luminaires which are significantly more energy efficient, using less electricity than older public lighting assets. Currently LED lights are the latest such technology. New public lighting technologies refers to equipment such as luminaires that TasNetworks does not provide, or may not exist, at the time of our distribution determination. However new technologies may become available during the next regulatory control period. Such technologies offer cost savings which local councils value as a benefit for their ratepayers.

TasNetworks has requested that a change to the classification of public lighting services be considered. TasNetworks stated:

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69 Aurora, *Information paper*, May 2010, p. 8; Aurora, *Prices for the provision of Street Lights for the period 1 July 2010 until 30 June 2011*, May 2010, p. 2.

> … TasNetworks … no longer has a monopoly over the provision of public lighting services. Public lighting services can now be considered a competitive activity where bilateral negotiation can produce more efficient, customer focussed outcomes. The service classification should reflect this competitive environment.[70]

Hobart City Council and Glenorchy City Council have also supported a review of the current classifications of public lighting services in Tasmania.

Hobart City Council stated:

> There may be other alternatives to the two categories of charges … which can provide a better overall outcome and this may be assisted by a more flexible arrangement for price setting, both for current and new technologies which is available through the Negotiated Distribution Service classification.[71]

Glenorchy City Council stated:

> The current classification of public lighting services as Direct Control / Alternative Control allows little scope for exploring different models of ownership and maintenance, whereas a Negotiated Distribution Service classification would allow greater scope for innovation in this area.[72]

Trans Tasman Energy Group also submitted that a reconsideration of current classifications is warranted. Trans Tasman Energy Group stated:

> Whilst the Alternative Control classification may have been appropriate where services (including light types) were expected to be the same throughout a regulatory period, it is not designed to establish services and prices for a market with potentially dynamic changes to technologies and provision of services.[73]

Our preliminary position is to retain the current classifications for public lighting services in Tasmania. Our reasons are discussed below. However we are seeking further views on the classification of these services. Below we discuss whether all public lighting services in Tasmania could be classified as negotiated services.

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[70] TasNetworks, Letter to AER, *TasNetworks' Framework and Approach for the 2017 Distribution Determination*, 22 October 2014.

[71] Hobart City Council, Submission, 18 March 2015.

[72] Glenorchy City Council, Submission, 19 March 2015.

[73] Trans Tasman Energy Group, Submission, 16 March 2015

Public lighting services (excluding new public lighting technology services)

Our preliminary position is to classify public lighting repair, maintenance, like-for-like replacement and the provision of new public lighting assets as a direct control service and further, as alternative control. This is consistent with our current approach. This section discusses our reasons for our preliminary position to classify public lighting as alternative control.

While TasNetworks does not have a legislative monopoly over public lighting services, a monopoly position exists to a large extent.[74] TasNetworks owns the majority of public lighting assets[75] and other parties need access to poles and easements to install their own public lighting assets. TasNetworks owns and controls this supporting infrastructure and there are safety restrictions on the qualifications of technicians working on and near this infrastructure. Therefore, similar to network services, ownership of network assets largely restricts the repair, maintenance, like-for-like replacement and provision of new public lighting assets to TasNetworks.[76] Therefore our preliminary position is to classify public lighting services, excluding new technology services, as direct control services.[77] This is consistent with the current classification.

As direct control services, we must further classify public lighting services as either standard control or alternative control services.[78] Our preliminary position is to classify public lighting as an alternative control service, consistent with current arrangements. We consider that this approach does not limit the scope for third parties and new entrants to provide public lighting services for new public lighting assets in the future. As an alternative control service, TasNetworks must directly attribute the costs of providing public lighting services to a specific set of customers, such as local councils.[79] We consider that transparency of the costs of providing public lighting services may encourage other potential service providers to enter the market.[80]

74 NEL, s. 2F(d).

75 NEL, s. 2F(a).

76 NEL, s. 2F(a)(d).

77 NER, clause 6.2.1.

78 NER, clause 6.2.2(c).

79 NER, clause 6.2.2(c)(3) and (5).

80 NER, clause 6.2.2(c)(1).

Applying the alternative control classification, there would be no material effect on administrative costs to us, TasNetworks, users or potential users, because we are retaining the current classification.[81]

New public lighting technology services

Our preliminary position on new public lighting technology is to continue the existing classification as a negotiated service.

In consultations for the Victorian F&A last year we received submissions that raised concerns that the current regime for implementing new technology in public lighting is slow and cumbersome.[82] We note these submissions had not suggested their concerns were due to the classification of public lighting. Rather, the issues confirmed that there remains a role for distributors and regulatory oversight in relation to many types of public lighting. However, we agree that classifying new public lighting technology services as direct control services would add an additional layer of economic regulation which may slow the adoption of emerging technologies. Consequently, we consider new public lighting technology services should continue to be classified as negotiated services.

Could public lighting be a negotiated service?

Our preference is to allow the competitive provision of services wherever practicable. We note the dissatisfaction expressed in submissions with the current approach to public lighting. While our preliminary position is to continue the current classification approach, we think there is a potential case to move to a negotiated service classification for all public lighting services.

Local councils are experienced in procuring services and are large customers relative to households and small businesses. Also, local councils are not required to ask TasNetworks to provide, operate and maintain their street lighting assets. As public lighting customers, they have the option of providing (and owning), operating and maintaining their own public lights, thereby avoiding TasNetworks' physical public lighting services (by using an 'energy only' service). As discussed above, TasNetworks has advised that a number of local councils in Tasmania are currently seeking to undertake the provision, maintenance and operation

81 NER, clause 6.2.2(c)(2).

82 AER, Final Framework and approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016, October 2014.

of public lighting services in their areas.[83] We consider the potential for alternative supply arrangements for both existing and new public lighting technology could provide countervailing power to local councils and place greater competitive pressure on the pricing and quality of public lighting services in Tasmania.

When public lighting is classified as an alternative control service, we must make a determination on the prices customers will pay. A distributor must ask us to approve its proposed capital and maintenance charges within the regulatory control period. This process provides transparency of the costs and certainty of the charges of providing public lighting services which may encourage other potential service providers to enter the market. Where a price cap form of control is applied to public lighting services, TasNetworks can charge below the cap in response to customer pressure, but is not required to. Allowing local councils to negotiate the price of their public lighting services under a negotiated services classification instead of alternative control may potentially be more effective in facilitating the availability of public lighting services that better meet customer preferences. However if local councils do not possess genuine countervailing power in negotiations the outcome may be frequent resort to regulatory intervention to arbitrate disputes which would involve additional regulatory costs to TasNetworks, local councils and other parties. This would not necessarily be a superior regulatory outcome.

Our views on this issue are preliminary and yet to be fully informed by stakeholder views. We encourage further submissions from local councils and other interested stakeholders on the potential to change our current approach.

We seek stakeholder submissions on the potential to classify all public lighting as a negotiated service.

1.3.4 Connection services

Chapter 10 of the rules defines connection services.[84] Put simply, a connection service refers to the services a distributor performs to:

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83 TasNetworks, Letter to AER, *TasNetworks' Framework and Approach for the 2017 Distribution Determination*, 22 October 2014.

84 NER, chapter 10 defines connection services as consisting of entry services and exit services. An entry service is a service provided to serve a generator or group of generators, or a network service provider or group of network service providers, at a single connection point. An exit service is a service provided to serve a distribution customer or a group of distribution customers, or a network service provider or group of network service providers, at a single connection point.

- connect a person's home, business or other premises to the electricity distribution network
- alter an existing connection to get more electricity from the distribution network than is possible at the moment
- extend the network to reach a person's premises.

Clause 26 of the ESI Act places an obligation on TasNetworks to connect a customer unless there is scope that the connection would:

- be detrimental to the network
- be in contravention of its licence conditions
- increase the risk of fire or damage to life or property.

In Tasmania, connection services can only be supplied by TasNetworks and we currently classify standard connection services and connections requiring augmentation as standard control services. The cost of connection services is therefore currently spread across all customers using the shared network excluding the cost of any up-front capital contributions made by customers requesting connection services. Customer contributions for connection augmentation are unregulated in the current regulatory control period.[85]

In October 2014 TasNetworks requested that a change to the classification of some connection services be considered. TasNetworks proposed that connection services that can be directly attributed to a single customer be classified as alternative control services.[86] TasNetworks subsequently advised AER staff that it had further considered its proposal to change the classification of pre-connection (design and application process) and new connection services from standard control to alternative control and was withdrawing the proposal.[87]

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85 When the 2012-17 determination was made there was no regulated guideline or arrangement to cover the quantum of capital contributions, or a dispute resolution mechanism. Connection and capital contributions procedures and policies were not subject to OTTER approval.

86 TasNetworks, Letter to AER, *TasNetworks' Framework and Approach for the 2017 Distribution Determination*, 22 October 2014.

87 Email from Bess Clark, TasNetworks to Darren Kearney, AER, 24 March 2015.

Our preliminary position is to retain the current classification for TasNetworks' connection services as standard control. Our reasons are set out below.

Connection charge guidelines

We have developed and published connection charge guidelines under chapter 5A of the NER to guide the development of connection policies by distributors.[88] Chapter 5A regulates connection by retail customers and came into effect in conjunction with the implementation of the National Electricity Customer Framework on 1 July 2012 which applies in Tasmania. A distributor's connection policy sets out the circumstances in which connection charges including capital contributions are payable and the basis for determining the amount of those charges. TasNetworks will be required to submit its connection policies for approval by the AER, consistent with the principles set out in clause 5A.E.1 of the NER and the AER's guidelines, as part of its pricing proposal for the 2017-22 regulatory control period.[89]

Referring to connection services and chapter 5A of the NER, TasNetworks stated:

> TasNetworks has set its customer contributions for the provision of these services during the current regulatory control period to be consistent with the provisions of chapter 5A. This means that all customers currently pay a 'fixed' contribution for the provision of these services, effectively a 'fee for services'.[90]

When determining the classification of services we examine the way in which the services are defined.[91] We are seeking to achieve as much consistency as practical across jurisdictions in the definition of these services. However, we recognise that the service classification applied may need to vary, taking account of historical jurisdictional practices and the degree of competition, or likelihood of competition developing, for these services.

As set out in our connection guidelines, we consider that a typical connection can be separated into at least four separate connection services, which can be broadly categorised in the following manner:

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88 AER, *Connection charge guidelines for electricity retail customers, Under chapter 5A of the National Electricity Rules*, June 2012.

89 The Consumer Challenge Panel's (CCP4) submission requested clarification on the future regulatory arrangements for connection services and capital contributions. Consumer Challenge Panel - Sub Panel CCP4, Submission, 10 March 2015.

90 TasNetworks, Letter to AER, *TasNetworks' Framework and Approach for the 2017 Distribution Determination*, 22 October 2014.

91 AER, *Final Decision, Connection charge guidelines: under chapter 5A of the National Electricity Rules, For retail customers accessing the electricity distribution network*, June 2012.

- Augmentation (insofar as it involves more than an extension)—any augmentation which is not an extension
- Extension—an augmentation that requires the connection of a power line or facility outside the present boundaries of the transmission or distribution network owned, controlled or operated by a Network Service Provider
- Augmentation of premises connection assets at the retail customer's connection point—we consider this would include any connection assets located on the retail customers premises
- Design and administration services—including administration, design, certification and inspection.

The exact nature of these connection services may differ between distributors and between different jurisdictions. Therefore we consider a distributor will define the specific connection services that it offers within each broad category. A distributor may also propose disaggregating the broad categories outlined above or propose further services.

Our connection charge guidelines can be applied to different classifications of connection services (and forms of control) adopted in our F&A paper. The guidelines do not pre-empt any decision we make or bind us to apply any particular service classification. However, we have set out the following factors as relevant to classification of connection services:[92]

- Where a service is offered in a competitive market, we may determine that no regulation of that market is required and so choose not to regulate the service
- If the cost of a connection service can be readily attributed to a particular customer, and the service is not contestable (or there is not a competitive market for the provision of the service), then an alternative control service classification may be appropriate. Augmentation of premises connection assets at the retail customer's connection point, extensions and incidental connection services, might generally fit into this category

92 AER, Final Decision, Connection charge guidelines: under chapter 5A of the National Electricity Rules, For retail customers accessing the electricity distribution network, p. 18, June 2012.

- If the cost of the connection cannot be easily attributed to an individual customer, then a standard control service classification might be appropriate. Augmentation (insofar as it involves more than an extension) might generally fit into this category

- We consider that standard control connection services should be undertaken to the least cost technically acceptable standard. If a distributor is requested to perform a standard control connection service to a higher standard, then it should propose an additional connection service specifically related to works performed to a higher standard than the least cost technically acceptable standard. It might be appropriate that the provision of connection assets to a standard greater than the least cost technically acceptable standard be classified as either alternative control or negotiated services.

Classification of TasNetworks connection services

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 network services, there is a regulatory barrier preventing any party other than TasNetworks providing connection services to its network.[93]

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 providers from competitively providing connection services.[94] These factors contribute to our preliminary view that TasNetworks possesses market power in providing connection services. Because of these barriers to competition from alternative service providers, we propose to continue classifying connection services as direct control services.[95]

Our preliminary position is to retain the current classification of connection services as standard control services as:

- There appears little, if any, prospect for competition in the market for connection services in Tasmania. That is, we are not aware of any Tasmanian Government initiatives to introduce contestability for

93 NEL, s. 2F(a).

94 NEL, s. 2F(d).

95 NEL, s. 2F(a)(d).

connection services in the next regulatory control period. Therefore, our classification will not influence the potential for competition.

- There would be no material effect on administrative costs to us, TasNetworks, users or potential users. This is because classifying connection services as standard control services is consistent with the current regulatory approach.
- We currently regulate connection services in most other NEM jurisdictions under a direct form of control. The services subject to direct control and alternative control differs across jurisdictions, reflecting historical regulatory approaches and the degree of competition, or likelihood of competition developing, for these services in each jurisdiction. For example, we do not regulate some New South Wales connection services, which are competitively available.
- The nature of basic connection services is that in most instances, the customer requesting the service will benefit from the provision of that service. As such, the costs are directly attributable to identifiable customers consistent with applying the alternative control service classification. However, the operation of Chapter 5A and our guidelines implement an efficiency test, such that a new customer would only make a capital contribution where the cost of the connection is greater than the incremental revenue the distributor will receive over the expected connection life of the service (i.e. cost-revenue test). That is, where a connection service is classified as standard control, provision for the requesting customer to make a capital contribution, where the application of the test means an upfront capital contribution is required, protects the broader customer base from incurring additional costs for services of no benefit to them. Equally, however, the cost-revenue test means that a new customer does not pay more than is efficient for the new connection.

This means the cost-revenue test applied to standard control services under our guidelines determines whether an additional upfront capital contribution is required in order to improve user pays signals and reduce the level of cross-subsidies between customers. The cost-revenue-test will result in an additional capital contribution for standard control connection services only if the cost of connecting a customer is greater than the anticipated level of revenue the DNSP will receive from that customer.[96]

We must act on the basis that there should be no departure from a previous classification unless another classification is clearly more appropriate.[97] We consider the current standard control classification supports the operation of Chapter 5A and our guidelines and provides a framework for consumers to understand where additional contributions may be required.

As discussed above, TasNetworks has previously raised whether some of its connection services should be classified as alternative control services. However, under this approach a new customer would have to pay the full costs of the connection service irrespective of whether this is offset by the incremental revenue the customer generates. We would be interested in feedback on whether any of TasNetworks' connection services would be more appropriately classified as alternative control services.

We seek stakeholder submissions on the potential to classify some of TasNetworks' connection services as alternative control.

1.3.5 Ancillary network services (fee based and quoted services)

For classification purposes, we propose to replace the current service groups called 'fee-based services' and 'quoted services' with a service group called 'ancillary network services'.

The existing 'fee based services' and 'quoted services' groupings describe the basis on which service prices are determined. We consider all of these services should be classified in a similar manner, regardless of how their regulated prices are determined.

Ancillary network services share the common characteristics of being routine and non-routine services provided to individual customers on an 'as needs' basis (e.g. energisation, de-energisation, re-energisation, meter testing, meter alteration, moving mains, services or meters, temporary supply, alteration and relocation of existing public lighting assets). Ancillary network services involve work on, or in relation to,

96 AER, Final Decision, Connection charge guidelines: under chapter 5A of the National Electricity Rules, For retail customers accessing the electricity distribution network, p. 7, June 2012.

97 NER, cl. 6.2.2(d).

parts of TasNetworks' distribution network. Therefore, similar to network services only TasNetworks can perform these services.

In October 2014 TasNetworks proposed that a change to the classification of some quoted services be considered.[98] TasNetworks subsequently advised AER staff that it had further considered its proposal to change the classification of some quoted services and was withdrawing the proposal.[99]

Our preliminary position is to retain the current alternative control service classification for quoted services which we have grouped within ancillary network services. Our reasons are set out below.

We consider that, similar to network services, there is a regulatory barrier preventing any party other than TasNetworks providing ancillary network services.[100] 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 providers from competitively providing ancillary network services.[101] These factors contribute to our preliminary view that, like network services, TasNetworks possesses market power in providing ancillary network services.

Because of these barriers to competition from alternative service providers, we propose to continue classifying ancillary network services as direct control services.[102]

Having decided to apply a direct control classification to ancillary network services, we must further classify these services as either standard control or alternative control. We intend to continue classifying ancillary network services as alternative control because they are attributable to individual customers.[103] We adopt this view even though ancillary network services do not exhibit signs of competition or potential for competition. We also note that there would be no material effect on the administrative costs to us, the

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98 TasNetworks, Letter to AER, *TasNetworks' Framework and Approach for the 2017 Distribution Determination*, 22 October 2014

99 Email from Bess Clark, TasNetworks to Darren Kearney, AER, 24 March 2015.

100 NEL, s. 2F(a).

101 NEL, s. 2F(d).

102 NEL, s. 2F(a)(d).

103 NER, clause 6.2.2(c)(5).

distributors, users or potential users.[104] This is because classifying ancillary network services as alternative control services is consistent with the current approach.

The nature of ancillary network services is that the customer requesting the service will benefit from that service. As such, the costs of that ancillary network service are directly attributable to an individual customer.[105] This results in costs that are more transparent for customers.

For these reasons, we intend to classify ancillary network services as alternative control services in the next regulatory control period.

1.4 AER's preliminary approach to service classification

In summary, we intend to group and classify TasNetworks' distribution services as set out in Appendix B.

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104 NER, clause 6.2.2(c)(2).

105 NER, clause 6.2.2(c)(5).

2 Control mechanisms

This attachment sets out our proposed form of control mechanisms to apply to TasNetworks' direct control services for the 2017–22 regulatory control period. This section also sets out our proposed approach to the formulae to give effect to the control mechanisms for direct control services.

Our distribution determination must impose controls over the prices (and/or revenues) of direct control services. This paper states our preliminary positions, together with our reasons, on the form(s) of the control mechanism(s) to apply to direct control services in the determination for the 2017–22 regulatory control period. We classify direct control services as standard control services or alternative control services. Different control mechanisms may apply to each of these classifications, or to different services within the same classification. Attachment 1 provides our proposed classification of Tasmanian distribution services.

We can only approve the forms of control in a distributor's regulatory proposal if is identical to that set out in our F&A paper.[106] 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 our F&A paper, unless we consider that unforeseen circumstances justify departing from the formulae set out in that paper.[107]

2.1 AER's preliminary position

Our preliminary position is to apply the following forms of control in the 2017–22 regulatory control period:

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

2.2 AER's assessment approach

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

106 NER, clause 6.12.3(c).

107 NER, clause 6.12.3(c1).

- the form of the control mechanisms[108]
- the formulae to give effect to the control mechanisms
- the basis of the control mechanism.[109]

The rules set out the control mechanisms that may apply to both standard and alternative control services:[110]

- 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[111]

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

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

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

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108 NER, clause 6.2.5(b).

109 NER, clause 6.2.6(a).

110 NER, clause 6.2.5(b).

111 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.

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

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

- revenue yield control (average revenue cap)

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

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

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

In considering our preliminary position, we have not considered a schedule of fixed prices or caps on the prices of individual standard control services. This is because we consider these direct price control mechanisms do not provide the level of flexibility within the regulatory control period for TasNetworks to manage distribution use of service charges shared across the broad customer base. Consequently, our assessment approach is focussed on a revenue cap or WAPC.

2.2.1 Standard control services

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

- 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.[112]

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

112 NER, clause 6.2.6(a).

Need for efficient tariff structures

Broadly, we consider prices are efficient if they reflect the underlying cost of supplying distribution services and take into account customers' willingness to pay.

Efficient pricing is important for several reasons. Where prices are cost reflective:

- allocative efficiency is maximised because consumers can compare the cost of providing the service to their needs and wants[113]
- 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
- a distributor can make efficient investment decisions. Because consumers base consumption decisions on the cost of providing the service compared to their value of consumption, increases and decreases in demand signal the potential need for extra network capacity.

Administrative costs

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

Existing regulatory arrangements

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

Desirability of consistency between regulatory arrangements

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

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113 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.

Revenue recovery

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

Pricing flexibility and stability

Price flexibility enables a distributor to restructure existing prices and/or introduce charges for new services. The stability and predictability of distribution network prices is important because it affects consumers' ability to manage bills and retailers' ability to manage risks incurred from changes to network prices.

Incentives for demand side management

Demand side management refers to the implementation of non-network solutions to avoid the need to build network infrastructure to meet increases in annual or peak demand.[114] As noted above, 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.

2.2.2 Alternative control services

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

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

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

- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)
- any other relevant factor.

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

We must state what the basis of the control mechanism is in our distribution determination.[115] This may utilise elements of Part C of chapter 6 of the rules with or without modification. For example, the control mechanism may use a building block approach or incorporate a pass-through mechanism.[116]

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

We consider that maintaining a revenue cap for standard control services in Tasmania best meets the factors set out under clause 6.2.5(c) of the rules.[117] We consider that a revenue cap will result in benefits to consumers through a higher likelihood of revenue recovery at efficient cost, better incentives for demand side management, less reliance on energy forecasts and better alignment with the introduction of efficient prices. Furthermore, we consider that the potential detriments of a revenue cap – within period pricing instability and weak pricing incentives – are able to be mitigated. We provide our consideration of these issues below.

2.3.1 Efficient tariff structures

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

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115 NER, clause 6.2.6(b).

116 NER, clause 6.2.6(c).

117 The Consumer Challenge Panel supported maintaining a revenue cap for standard control services. Consumer Challenge Panel - Sub Panel CCP4, Submission, 10 March 2015.

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

While there are a variety of methods of incorporating these characteristics, we consider that the resulting prices from each will include many of the same features. First, because for the majority of distributors the costs of supply are fixed or relate to peak demand, efficient prices will generally be structured around fixed or peak prices.[118] Second, because customers' willingness to pay for connection to the network is generally higher than for electricity consumption, where the price must be set above the cost of supply, the largest margin is likely to be applied to fixed (connection) prices.

To illustrate relative efficiency of different tariff structures, we have previously compared the Queensland distributors, under a revenue cap, and the NSW distributors under a WAPC. In general, we concluded that tariff structures that include a greater reliance on time of use (or load control tariffs) or fixed charges are more efficient than tariffs based simply on the accumulated energy consumption. We published a discussion on the efficiency of different tariff structures last year.[119] In reviewing the form of control in NSW[120] we found that a WAPC had not encouraged the NSW distributors to adopt efficient prices, despite theory that suggested this should be an outcome of a WAPC.

Figure 4 below compares the Queensland distributors under their current revenue cap and the WAPC the NSW distributors have operated under in recent years. From the figures below we can see that despite operating under a revenue cap, the Queensland distributors have a higher proportion of revenues raised through prices we regard as more efficient, such as fixed price components and prices for controlled loads. We concluded from this evidence that a revenue cap has not discouraged the adoption of more efficient tariff structures.

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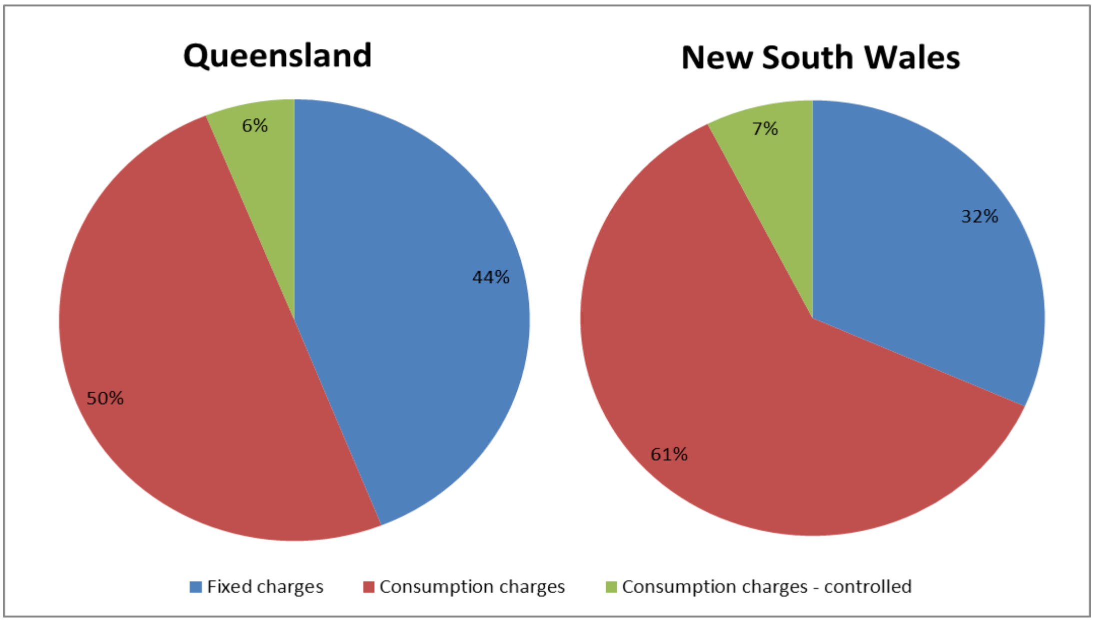
118 Peak prices include peak energy, demand and capacity prices.

119 AER, *Stage 1 NSW framework and approach Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, p. 45

120 AER, *Stage 1 NSW framework and approach Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, p. 45.

Figure 4: Queensland and NSW distributors' revenue type



Source: AER. Qld DNSPs' revenue type is for 2012–13 while NSW DNSPs' revenue type is for 2008–09.

A significant issue in recent times has been the widespread difficulty experienced in all sectors of the NEM in accurately forecasting customer demand. Despite economic growth and renewed business activity across the nation following the global financial crisis, energy demand has continued to exhibit a downward trend. This trend is widely attributed to a range of factors including higher energy efficiency, widespread penetration of solar, higher prices and increased customer concern about climate change. This makes the future forecasting of demand a very difficult task for all in the industry

We consider the risks to consumers of incurring higher costs are exacerbated under a WAPC in a situation where an unanticipated negative trend in the rate of energy use may continue. Consequently, we consider this risk is better managed under a revenue cap.

2.3.2 Administrative costs

We consider that there is little difference in administrative costs between control mechanisms under the building block framework in the long run. However, we note that a change to a WAPC would likely result in increased administrative costs in the short run. Under a WAPC revenue is variable within the regulatory control period which results in higher revenue risk to a distributor. This would likely lead to increased costs through risk minimisation strategies. Furthermore, maintaining a revenue cap in Tasmania will likely lead to reduced administrative costs to users and us due to consistency across and between regulatory arrangements. We are proposing the introduction of a revenue cap in Victoria, South Australia and New South Wales. This consistency will lead to reduced administrative costs for us through standardisation of modelling approaches, incentive schemes and consultation requirements.

2.3.3 Existing regulatory arrangements

We consider that consistency across regulatory control periods is generally desirable but also needs to be weighed against the other factors under clause 6.2.5(c) of the rules. Having had regard to these factors we consider it appropriate to maintain a revenue cap for standard control services in Tasmania. The outcomes under the factors further the national electricity objectives and are consistent with the revenue and pricing principles.

2.3.4 Desirability of consistency between regulatory arrangements

We consider that consistency between regulatory arrangements is generally desirable but also needs to be weighed against the other factors under clause 6.2.5(c) of the rules. Having had regard to these factors we consider it appropriate to maintain a revenue cap for standard control services in Tasmania. The outcomes under the factors further the national electricity objectives and are consistent with the revenue and pricing principles.

2.3.5 Revenue recovery

We consider that a revenue cap provides a high likelihood of efficient cost recovery. We consider that because costs for a distributor are largely fixed and unrelated to energy sales, revenue recovery should also be largely fixed and unrelated to energy sales.

We consider that a WAPC does not provide a high or even reasonable likelihood of efficient cost recovery. We consider the WAPC provides an opportunity for distributors to recover revenue systematically above forecast. In contrast a revenue cap sets a maximum allowable revenue (MAR) for each year of the regulatory control period. A distributor must then recover revenue equal to or less than the MAR.

2.3.6 Pricing flexibility and stability

We consider that price flexibility for existing tariffs and tariff structures is similar for all forms of control and that it is influenced by the side constraints and the pricing principles in the rules.

We consider that the revenue cap results in increased pricing flexibility in relation to the introduction of new tariffs and tariff structures. Under a revenue cap, to introduce a new tariff or tariff structure a distributor is required to submit reasonable forecasts for that tariff. As there is no revenue at risk because revenue is fixed over the regulatory control period, the incentive to manipulate such forecasts is low.

2.3.7 Pricing stability

We consider price instability can occur under all forms of control mechanisms. This is because the rules require various annual price adjustments regardless of the control mechanism.[121]

We consider that there is increased likelihood of overall price instability within a regulatory control period under a revenue cap. That is, the distributors must adjust prices during the regulatory control period to account for differences between forecast and actual sales volumes. The difference is added to what is called an unders and overs account. The balance of this account is then added to future revenue requirements to make certain the revenue cap is achieved.

Generally the balance of the unders and overs account is adjusted for in full at the first opportunity. In Tasmania,[122] we designed the unders and overs account for the current regulatory period as a rolling account with an estimate year to help smooth the price adjustments year on year.[123] We consider that incorporating forecast sales in forming the X-factors in the distribution determination will result in lower balances in the unders and overs account.[124]

We consider the WAPC can increase overall price stability within the regulatory control period compared to a revenue cap. However, a WAPC is unlikely to lead to increased price stability or predictability for

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121 These include cost pass throughs, jurisdictional scheme obligations, tribunal decisions and transmission prices passed on to the distributors from Transmission Network Service Providers.

122 AER, *Final distribution determination, Aurora Energy Pty Ltd, 2012–13 to 2016–17, attachments*, April 2012, pp. 2–24.

123 AER, *Final Distribution Determination Aurora Energy Pty Ltd 2012–13 to 2016–17*, pp. 20–23, April 2012.
This approach means that instead of waiting two years before incorporating the under or over recovery into prices, an estimate (based on nine months of data) used in the calculation of the under or over recovery. This will reduce the likelihood of undesirable price shocks by smoothing the under and over recovery using more updated and accurate estimated and forecast data in the middle year.

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

individual tariffs or customers. Under a WAPC a distributor faces an incentive to re-balance tariffs to maximise profit and this incentive may result in large changes to tariffs within the regulatory control period.

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

A further aspect to consider is the effect on price volatility stemming from the form of control between regulatory control periods. In moving from one regulatory control period to the next, a WAPC would likely subject consumers to large price increases if there are demand forecasting errors. That is, under a WAPC a distributor has the opportunity to recover revenue substantially above forecast revenue when actual quantities exceed forecast quantities. Similarly, they are able recover revenue close to forecast when actual quantities are below forecast quantities. The revenue cap avoids this as demand only forms a small component of forecasting revenue requirements. This results in less price volatility and therefore less movement in prices for consumers between regulatory control periods.

2.3.8 Incentives for demand side management

We consider a revenue cap provides an efficient incentive to undertake demand side management.

Under a revenue cap we fix a distributor's revenue over the regulatory control period. A distributor can therefore increase profits by reducing costs. This creates an incentive for a distributor to undertake demand side management projects that reduce total costs.[125] We consider this provides an efficient incentive for a distributor to undertake demand side management within a regulatory control period.

125 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.

Under a WAPC a distributor's profits are linked directly to the actual volumes of electricity distributed. This means that even when implementation of a demand side management project would reduce a distributor's total costs it will likely face a disincentive to undertake the project because the costs of implementation plus the reduction in revenue will outweigh the reduction in network expenditure.

2.3.9 Hybrid form of control

We consider that higher administrative costs to distributors and us under a hybrid revenue cap outweigh the potential benefits of this form of control.

We have considered adjustment mechanisms (hybrid control mechanisms) to the revenue cap for variations from forecast peak demand and customer numbers, to account for the differences in a distributor's costs arising from such variations. That is, a form of control that allows revenue to be adjusted within the regulatory period to reflect deviations from forecast cost drivers. This design enables a distributor's revenues to align more closely to the cost drivers compared with a standard revenue cap. However, it may be difficult to develop an effective revenue function under a hybrid revenue cap resulting in the need to recalculate a distributor's maximum allowable revenue each year. This would involve substantial administrative costs throughout the regulatory control period. Additionally, because a large proportion of a distributor's costs are fixed rather than variable such adjustments may only result in small adjustments to a distributor's maximum allowable revenue. For these reasons, the Independent Pricing and Regulatory Tribunal (NSW) moved away from a hybrid revenue cap to a revenue cap in the 1999–2004 distribution determination.[126] Other regulators (Queensland Competition Authority and OTTER) have also noted the difficulties and complexities involved in developing and applying a hybrid revenue cap.[127]

2.3.10 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.[128] We must include the formulae in our final

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126 IPART, *Form of Economic Regulation for NSW Electricity Network Charges: Discussion Paper 48*, August 2001, p. 10.

127 QCA, *Final Determination – Regulation of Electricity Distribution*, May 2005, p. 30; OTTER, *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices*, September 2003, p. 99.

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

F&A in our distribution determination, unless we consider that unforeseen circumstances justify departing from the formulae as set out in the F&A.[129]

Below are proposed formulae to apply to TasNetworks' standard control services. We consider that the formula gives effect to the revenue cap.

(1) $$MAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_{ij}^{t} q_{ij}^{t*}$$ i=1,...,n and j=1,...,m and t=1,...,5

(2) $$MAR_t = AAR_t + I_t + T_t + B_t$$ t = 1,2,...,5

where;

(3) $$AAR_1 = AR_1(1 + S_t''')$$ t = 1

(4) $$AAR_t = AAR_{t-1}(1 + CPI_t)(1 - X_t)(1 + S_t)$$ t = 2,3,4,5

Where:

MAR_t is the maximum allowable revenue in year t.

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

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

AR_t is the annual smoothed revenue requirement in the Post Tax Revenue Model for year t. Adjusted as necessary to account for any difference between actual inflation and estimated inflation.

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

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129 NER, clause 6.12.3(c1).

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

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

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

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

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 final decision.

S_t''' is the sum of the s-factors for all parameters after application of the s-bank adjusted for the change in the annual revenue requirement between the last year of the 2012-2017 regulatory control period to 2017-18.

S_t is the s-factor for regulatory year t.

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

Our preliminary position is to apply caps on the prices of individual services in the next regulatory control period to all alternative control service.[130] We propose classifying the following services as alternative control services:

- type 5-7 metering services
- public lighting services (excluding new public lighting technology services)
- ancillary network services (fee based and quoted services).

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

Our main consideration is that the benefit of caps on the prices of individual services is providing cost reflective pricing. We consider this benefit outweighs any detriment from increased administrative costs.

Through the distribution determination process, we will confirm the basis of the control mechanism for alternative control services.[131] That is, we will confirm whether we will set prices using a building block approach or another method. Prices for non-standard ancillary network services will be determined on a quoted basis. TasNetworks will propose the approach to determining quoted prices, which we will consider in making our distribution determination. Typically, 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.

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

2.4.1 Influence on the potential to develop competition

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

2.4.2 Administrative costs

Our preliminary view is that there will be no material impact on administrative costs for metering, ancillary network and public lighting services because we are continuing with caps on prices of individual services.

2.4.3 Existing regulatory arrangements

We consider consistency across regulatory control periods is generally desirable. However, we consider consistency across regulatory control periods should not be our primary consideration in determining a

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[131] The basis of the control mechanism is the method used to calculate the revenue to be recovered or prices to be set for a group of services. Clause 6.2.6(b) of the rules states that for alternative control services, the control mechanism must have a basis stated in the distribution determination. We are able to apply a control mechanism to a distributor's alternative control services as set out under chapter 6, Part C of the rules. This involves applying the building block approach, although we may only apply certain elements of the building block approach. Alternatively, we may implement a control mechanism that does not use the building block approach.

control mechanism. Our consideration of other factors in clause 6.2.5(d) of the rules leads us to the conclusion that price caps for individual services would lead to an overall outcome more consistent with the NEO and revenue and pricing principles than the other possible alternatives.

For metering, public lighting and ancillary network services, our preliminary position to apply caps on the prices of individual services is consistent with the current regulatory arrangements in Tasmania.

2.4.4 Desirability of consistency between regulatory arrangements

We consider consistency across jurisdictions is generally desirable but is not primary to our considerations. Desirability needs to be weighed against the other factors under clause 6.2.5(c) of the rules. Having considered these factors we have concluded that price caps for individual services would lead to an overall outcome more consistent with the NEO and revenue and pricing principles than the other possible alternatives.

2.4.5 Cost reflective prices

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

2.4.6 Formulae for alternative control services

We are required to set out our proposed approach to the formulae that give effect to the control mechanisms for alternative control services in the F&A paper.[132] We must include the formulae in our final

[132] NER, clause 6.8.1(b)(2)(ii).

F&A in our distribution determination, unless we consider that unforeseen circumstances justify departing from the formulae as set out in the F&A paper.[133]

We propose to apply price cap formulae as set out below to the following services classified as alternative control in this preliminary positions paper:

- type 5-7 metering services
- public lighting services (excluding new public lighting technology services)
- ancillary network services (fee based and quoted services).

Below are proposed formulae to apply to alternative control services. We consider that the formula gives effect to the cap on the prices of individual services:

$$\overline{p}_i^t \geq p_i^t \qquad i=1,\ldots,n \text{ and } t=1,2,3,4$$

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

Where:

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

p_i^t is the price of service i in year t. The initial value is to be decided in the final decision.

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

X_i^t is the X-factor for service i in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. To be decided in the final decision.

133 NER, clause 6.12.3(c1).

3 Incentive schemes

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

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

3.1 Service target performance incentive scheme

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

Our national distribution STPIS[134] provides a financial incentive to distributors to maintain and improve service performance. The STPIS aims to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributor's incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (NEO).

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

- The service standards factor (s-factor) adjustment to the annual revenue allowance for standard control services rewards (or penalises) distributors for improved (or diminished) service compared to predetermined targets. Targets relate to service parameters pertaining to reliability and quality of supply, and customer service.

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

- A guaranteed service level (GSL) component composed of direct payments to customers[135] experiencing service below a predetermined level.[136]

While the mechanics of how the STPIS will operate are outlined in our national distribution STPIS, 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
- the applicable parameters for the s-factor adjustment of annual revenue across customer service, reliability and quality of supply components
- performance targets for the applicable parameters in each network segment
- the criteria for certain events to be excluded from the calculation of annual performance and performance targets
- incentive rates determining the relative importance of measured performance (against targets) across applicable parameters in each network segment.

TasNetworks can propose to vary the application of the STPIS in its regulatory proposal.[137] We can accept or reject the proposed variation in our determination. Each applicable 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 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.[138] A distributor

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135 Except where a jurisdictional electricity GSL requirement applies.

136 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.

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

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

proposing a delay must provide in writing its reasons and justification for believing that the delay will result in reduced price variations to customers.

Our national STPIS currently applies to TasNetworks which is subject to financial penalty or reward of ±5 per cent through an s-factor adjustment to revenue. GSLs are provided for through the *Tasmanian Electricity Code's* (TEC's) GSL scheme, so the GSL component of the AER's STPIS does not apply.

3.1.1 AER's preliminary position

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

- set revenue at risk for TasNetworks within the range ±5 per cent.
- segment the network according to TEC supply reliability categories (critical infrastructure, high density commercial, urban, high density rural and low density rural)
- set applicable reliability of supply (system average interruption duration index or SAIDI and system average interruption frequency index of SAIFI) and customer service (telephone answering) parameters
- set performance targets based on TasNetworks' average performance over the past five regulatory years
- apply the methodology indicated in the national STPIS for excluding specific events from the calculation of annual performance and performance targets
- apply the methodology and value of customer reliability (VCR) values as indicated in our national STPIS to the calculation of incentive rates.

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

The Consumer Challenge Panel submitted that we should consider whether changes should be made to standardise the application of the STPIS across all distribution networks.[139]

We recognise recent policy reviews that will impact on our development and application of the STPIS. In September 2014 the AEMC completed a review of distribution reliability measures in the NEM.[140] As discussed in more detail below, the Australian Energy Market Operator (AEMO) has also completed analysis on how willing consumers are to pay for improvements in network reliability.[141] We intend to review the application of our national STPIS to incorporate the findings of these reviews before finalising our draft determination for TasNetworks in September 2016.

3.1.2 AER's assessment approach

The rules require us to have regard to several factors in developing and implementing a STPIS for TasNetworks.[142] 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
  - 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

139 Consumer Challenge Panel - Sub Panel CCP4, Submission, 10 March 2015.

140 AEMC, *Final Report, Review of distribution reliability measures*, 5 September 2014.

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

142 NER, clause 6.6.2(b).

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

Our approach and reasons for developing the STPS are contained in our final decision for the national distribution STPIS.[143]

3.1.3 Reasons for AER's preliminary 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.[144] 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.

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

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

Benefits to consumers

We are mindful of the potential impact of the STPIS on consumers. Under the rules, we must consider customers' willingness to pay for improved service performance so benefits to consumers are sufficient to warrant any penalty or reward under the STPIS.[145]

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

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

The VCR estimates currently in our national STPIS are taken from studies conducted for the Essential Services Commission Victoria and Essential Services Commission of South Australia.[146]

In September 2014 AEMO completed analysis of the VCR across the NEM.[147] This analysis will impact on our future development and application of the STPIS. However we consider there is insufficient time to conduct a comprehensive review of the STPIS before TasNetworks submits its proposal for the next regulatory control period in January 2016. Therefore our preliminary approach is to apply the national STPIS in its current form having regard to recent policy reviews that impact on its application. For example, we propose to apply the 2014 AEMO Tasmania VCR to calculate the incentive rates for TasNetworks as this approach better meets the STPIS objectives. Clause 3.2.2(a) of the STPIS allows us to apply alternative incentive rates that are not based on the VCR set out in clause 3.2.2(b) of the scheme. When

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145 NER, clause 6.6.2(b)(3)(vi).

146 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.

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

we developed the STPIS, we considered the VCR figures should be based on the most recent documented and robust work on reliability incentive rates.[148] AEMO has undertaken a thorough review of the VCR across the NEM surveying approximately 3000 residential, business and direct-connect customers across all NEM states and adopting a methodology through extensive stakeholder consultation and review by independent experts.

TasNetworks has referred to recent customer consultation it has undertaken where it found that customers are generally not seeking or wanting to pay for improvements in the current levels of reliability. TasNetworks has also commented on the operation of the STPIS in Tasmania in the current regulatory control period, noting the scheme's rewards and penalties do not provide for sustainable and predictable pricing outcomes for customers. TasNetworks considers that the variation could be limited by applying lower rewards and penalties under the scheme.[149]

Our preliminary position is to maintain revenue at risk for TasNetworks within the range ±5 per cent as we do not consider that a lower level would better meet the objectives of the STPIS.

We note that the revised AEMO VCR values referred to above are lower than the values currently in the STIPIS. If the 2014 AEMO Tasmania VCR is applied in the next regulatory control period this will act to moderate pricing outcomes arising from the operation of the scheme. This is consistent with the STPIS objectives as the pricing outcomes would reflect the most recent customers' willingness to pay for improved performance in the delivery of services. Also, as discussed above, our STPIS includes a banking mechanism to limit price volatility for customers.

TasNetworks has operated under service incentive schemes for a number of regulatory control periods, that is, under the STIPIS in the current period and previously under a Tasmanian scheme administered by OTTER. We consider that TasNetworks is familiar with service incentive schemes and the operational measures required to maintain or improve its service performance given the level of revenue at risk. We note TasNetworks' view that its customers are generally not seeking or wanting to pay for improvements in the current levels of reliability, however we consider it less likely that customers would be satisfied with a

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148 AER, *Electricity distribution network service providers Service target performance incentive scheme*, Final decision, June 2008, p 17.

149 TasNetworks, *TasNetworks' Framework and Approach for the 2017 Distribution Determination*, Letter, 22 October 2014.

deterioration in reliability. We note that the potential for deterioration in service performance will increase if revenue at risk is reduced under the STIPIS.

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

We seek stakeholder submissions on the level of revenue at risk applied to TasNetworks under the STIPIS.

Balanced incentives

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

Defining performance targets

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

The rules require us to consider past performance of the distributor's network in developing and implementing the STPIS.[150] Our preferred approach is to base performance targets on TasNetworks' average performance over the past five regulatory years.[151] Using an average calculated over multiple years instead of applying performance targets based solely on the most recent regulatory year limits a distributor's incentive to underperform in the final year of a regulatory control period to make future targets less onerous.

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

150 NER, clause 6.6.2(b)(3)(iii).

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

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

Interactions with our other incentive schemes

In applying the STPIS we must consider any other incentives available to the distributor under the rules or relevant distribution determination.[152] 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 efficiencies arising through reduced service performance for customers. The s-factor adjustment of annual revenue depends on the distributor's actual service performance compared to predetermined targets. In accordance with the rules we must set incentive rates to offset any financial incentives the distributor may have to reduce costs at the expense of service levels.[153]

In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.[154]

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

152 NER, clause 6.6.2(b)(3)(iv).

153 NER, clause 6.6.2(b)(3)(v).

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

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

3.2 Efficiency benefit sharing scheme

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

The Consumer Challenge Panel submitted that we should comment on whether and how the EBSS would be applied.[155]

This section sets out our preliminary position and reasons on how we intend to apply the EBSS to TasNetworks in the next regulatory control period.

3.2.1 AER's preliminary position

We propose applying our new EBSS[156] to TasNetworks for the 2017–22 regulatory control period.

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

3.2.2 AER's assessment approach

The EBSS must provide for a fair sharing between a distributor and network users of opex efficiency gains and efficiency losses.[157] We must also have regard to the following factors in developing and implementing the EBSS:[158]

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155 Consumer Challenge Panel - Sub Panel CCP4, Submission, 10 March 2015.

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

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

3.2.3 Reasons for AER's preliminary position

The current EBSS applies to TasNetworks in the 2012-17 regulatory control period.[159] As part of our Better Regulation program we consulted on and published the new EBSS, taking into account the requirements of the rules.

The new EBSS retains the same form as the current EBSS, and merges the distribution and transmission schemes. Changes in the new EBSS relate to the criteria for adjustments and exclusions under the scheme.[160] We also amended the scheme to provide flexibility to account for any adjustments made to base year opex to remove the impacts of one-off factors. The new EBSS also clarifies how we will determine the carryover period. These revisions affect how carryover amounts are calculated for future regulatory control periods.[161]

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

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[157] NER, clause 6.5.8(a).

[158] NER, clause 6.5.8(c).

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

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

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

In developing the new EBSS we had regard to the requirements under the rules, as set out in the scheme and accompanying explanatory statement.[162] This reasoning extends to the factors we must have regard to in implementing the scheme.

The EBSS must provide for a fair sharing of efficiency gains and losses.[163] Under the scheme distributors and consumers receive a benefit where a distributor reduces its costs during a regulatory control period and both bear some of any increase in costs.

Under the EBSS, positive and negative carryovers reward and penalise distributors for efficiency gains and losses respectively.[164] The EBSS provides a continuous incentive for distributors to achieve opex efficiencies throughout the subsequent period. This is because the distributor receives carryover payments so it retains any efficiency gains or losses it makes within the regulatory period for the length of the carryover period. This is regardless of the year in which it makes the gain or loss.[165]

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

The EBSS also leads to a fair sharing of efficiency gains and losses between distributors and consumers.[166] For instance the combined effect of our forecasting approach and the EBSS is that opex efficiency gains or losses are shared approximately 30:70 between distributors and consumers. This means for a one dollar efficiency saving in opex the distributor keeps 30 cents of the benefit while consumers keep 70 cents of the benefit. Example 1 shows how the EBSS operates. It illustrates how the benefits of a permanent efficiency improvement are shared approximately 30:70 between a network service provider and consumers.[167]

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

163 NER, clause 6.5.8(a).

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

165 NER, clause 6.5.8(c)(2).

166 NER, clause 6.5.8(c)(1).

167 See also: AER, Explanatory statement, Efficiency benefit sharing scheme for electricity network service providers, 29 November 2013.

Example 1 How the EBSS operates

	Regulatory period 1					Regulatory period 2					Future
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	
Forecast (F_t)	100	100	100	100	100	95	95	95	95	95	95 p.a.
Actual (A_t)	100	100	100	95	95	95	95	95	95	95	95 p.a.
Underspend ($F_t - A_t = U_t$)	0	0	0	5	5	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	0	0	0	5	0	0*	0	0	0	0	0 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			0	0	0	0	0				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					5	5	5	5	5		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						5	5	5	5	0	0 p.a.
Benefits to NSP ($F_t - A_t + C_t$)	0	0	0	5	5	5	5	5	5	0	0 p.a.
Benefits to consumers ($F_1 - (F_t + C_t)$)	0	0	0	0	0	0	0	0	0	5	5 p.a.
Discounted benefits to NSP**	0	0	0	5	4.7	4.5	4.2	4.0	3.7	0	0
Discounted benefits to consumers**	0	0	0	0	0	0	0	0	0	3.5	58.8***

Notes: * At the time of forecasting opex for the second regulatory period we don't know actual opex for year 5. Consequently this is not reflected in forecast opex for the second period. That means an underspend in year 6 will reflect any efficiency gains made in both year 5 and year 6. To ensure the carryover rewards for year 6 only reflect incremental efficiency gains for that year we subtract the incremental efficiency gain in year 5 from the total underspend. In the example above, $I_6 = U_6 - (U_5 - U_4)$.

** Assumes a real discount rate of 6 per cent.

*** As a result of the efficiency improvement, forecast opex is $5 million p.a. lower in nominal terms. The estimate of $58.7m is the net present value of $5 million p.a. delivered to consumers annually from year 11 onwards.

In implementing the EBSS we must also have regard to any incentives distributors may have to capitalise expenditure.[168] Where opex incentives are balanced with capex incentives, a distributor does not have an incentive to favour opex over capex, or vice-versa. The CESS is a symmetric capex scheme with a 30 per cent incentive power. This is consistent with the incentive power for opex when we use an unadjusted base year approach in combination with an EBSS. During the subsequent period when the CESS and EBSS are applied, incentives will be relatively balanced, and a distributor should not have an incentive to favour opex over capex or vice versa. We discuss the CESS further in section 3.3.

We must also consider the possible effects of implementing the EBSS on incentives for non-network alternatives:[169]

- Expenditure on non-network alternatives generally takes the form of opex rather than capex. Successful non-network alternatives should result in the distributor spending less on capex than it otherwise would have. Non-network alternatives and demand management incentives are discussed further in section 3.4.
- When the CESS and EBSS both apply, a distributor has an incentive to implement a non-network alternative if the increase in opex is less than the corresponding decrease in capex. In this way the distributor will receive a net reward for implementing the non-network alternative.[170] This is because the rewards and penalties under the EBSS and CESS are balanced and symmetric. In the past where the EBSS operated without a CESS, we excluded expenditure on non-network alternatives when calculating rewards and penalties under the scheme. This was because a distributor may otherwise receive a penalty for increasing opex without a corresponding reward for decreasing capex.[171]

168 NER, clause 6.5.8(c)(4).

169 NER, clause 6.5.8(c)(5).

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

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

3.3 Capital expenditure sharing scheme

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

The CESS approximates efficiency gains and efficiency losses by calculating the difference between forecast and actual capex. It shares these gains or losses between 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 to work out what the distributor's share of the underspend or overspend should be.
- We calculate the CESS payments taking into account the financing benefit or cost to the distributor of the underspends or overspends.[172] 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 an underspend or overspend, while consumers retain 70 per cent of the underspend or overspend. This means that for a one dollar saving in capex the distributor keeps 30 cents of the benefit while consumers keep 70 cents of the benefit.

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172 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.

3.3.1 AER's preliminary position

Our preliminary position is to apply the CESS, as set out in our capex incentives guideline,[173] to TasNetworks in the next regulatory control period.

3.3.2 AER's assessment approach

In deciding whether to apply a CESS to a distributor, and the nature and details of any CESS to apply to a distributor, we must:[174]

- make that decision in a manner that contributes to the capex incentive objective[175]
- consider the CESS principles,[176] capex objectives,[177] other incentive schemes, and where relevant the opex objectives, as they apply to the particular distributor, and the circumstances of the distributor.

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

3.3.3 Reasons for AER's preliminary position

The Consumer Challenge Panel submitted that we should comment on whether the CESS would be applied to TasNetworks.[178]

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

TasNetworks is not currently subject to a CESS. As part of our Better Regulation program we consulted on and published version 1 of the capex incentives guideline which sets out the CESS.[179] The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-

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

174 NER, clause 6.5.8A(e).

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

176 NER, clause 6.5.8A(c).

177 NER, clause 6.5.7(a).

178 Consumer Challenge Panel - Sub Panel CCP4, Submission, 10 March 2015.

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

forward the RAB.[180] We are also proposing to apply forecast depreciation, which we discuss further in attachment 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 of underspends and overspends happens at the end of each regulatory period when we update a distributor's RAB to include new capex. If a distributor spends less than its approved forecast during a period, it will benefit within that period. Consumers benefit at the end of that period when the RAB is updated to include less capex compared to if the business had spent the full amount of the capex forecast. This leads to lower prices in the future.

Without a CESS the incentive for a distributor to spend less than its forecast capex declines throughout the period.[181] Because of this a distributor may choose to spend capex earlier, or spend on capex when it may otherwise have spent on opex, or less on capex at the expense of service quality—even if it may not be efficient to do so.

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

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

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

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

3.4 Demand management incentive scheme

This section sets out our preliminary approach and reasons for applying a demand management incentive scheme (DMIS) to TasNetworks in the next regulatory control period.[182]

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

This underutilisation means that augmentation of network capacity may not always be the most efficient means of catering for increasing peak demand. Demand management refers to any effort by a distributor to lower or shift the demand for standard control services.[183] Demand management that effectively reduces network utilisation during peak usage periods can be an economically efficient way of deferring the need for network augmentation.

The rules require us to develop and implement mechanisms to incentivise distributors to consider economically efficient alternatives to building more network.[184] To meet this requirement, and motivated by the need to improve TasNetworks' capability in the demand management area, we implemented a DMIS in our distribution determination for the current regulatory period.

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

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

184 NER, clause 6.6.3(a).

The current DMIS applying to TasNetworks provides for a demand management innovation allowance (DMIA) to be incorporated into TasNetworks' revenue allowance for each year of the regulatory control period. TasNetworks prepares an annual report on their expenditure under the DMIA[185] in the previous year, which we then assess against specific criteria.

DMIS previously applying in other jurisdictions also compensate a distributor for any foregone revenue demonstrated to have resulted from demand management initiatives approved for a distributor under a weighted average price cap. 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 in the current regulatory control period it is subject to a revenue cap form of control. As a revenue cap is expected to apply in the next regulatory control period, compensation for foregone revenue will not be relevant to TasNetworks in the next regulatory control period.

3.4.1 AER's preliminary position

Our preliminary position is to continue applying the DMIS to TasNetworks in the next regulatory control period.

The Consumer Challenge Panel commented on the application of the DMIS across the NEM referring to issues of consistency of allowances and coordination of approaches supporting demand management.[186]

We acknowledge the need to reform the existing demand management incentive arrangements. The AEMC is currently consulting on rule change requests from the Total Environment Centre (TEC) and the Council of Australian Governments' Energy Council (COAG Energy Council) regarding reform of the DMIS under Chapter 6 of the NER. [187] The requests are in response to recommendations made by the AEMC in its

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

[186] Consumer Challenge Panel - Sub Panel CCP4, Submission, 10 March 2015.

[187] AEMC, *Consultation paper, National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, 19 February 2015.

Power of Choice review.[188] We intend to develop and implement a new DMIS during the next regulatory control period, depending on the progress of the rule change process.

3.4.2 AER's assessment approach

The rules require us to have regard to several factors in developing and implementing a DMIS for TasNetworks.[189] These are:

- Benefits to consumers
  - the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme
  - the willingness of customers to pay for increases in costs resulting from implementing a DMIS.
- Balanced incentives
  - the effect of a particular control mechanism (that is, price as distinct from revenue regulation) on a distributor's incentives to adopt or implement efficient non-network alternatives
  - the effect of classification of services on a distributor's incentive to adopt or implement efficient embedded generator connections
  - the extent the distributor is able to offer efficient pricing structures
  - the possible interactions between a DMIS and the other incentive schemes.

3.4.3 Reasons for AER's preliminary position

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

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

189 NER, clause 6.6.3(b).

Benefits to consumers

Customers ultimately fund the DMIA adjustment to a distributor's annual revenue each year. As such, we are mindful of the potential impact of the DMIS on consumers. Under the rules, we must consider customers' willingness to pay for any higher costs resulting from the scheme so benefits to consumers are sufficient to warrant any penalty or reward.[190]

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

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

While studies[191] indicate that customers are supportive of demand management initiatives in principle, we know little about their willingness to pay. We consider our proposed application of the DMIS to be suitable in light of this limited information, given that the modest level of the DMIA means potential price increases will be minimal.

Balanced incentives

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

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190 NER, clause 6.6.3(b)(1).

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

Control mechanism and service classification

The rules require us to have regard for how a distributor's control mechanism influences its incentives to adopt or implement efficient non-network alternatives to network augmentation.[192] We consider that a revenue cap form of control does not provide a disincentive for TasNetworks to reduce the quantity of electricity as approved regulated revenues are not dependent on the quantity of electricity sold. That is, under a form of control where revenue is at least partially dependent on the quantity of electricity sold (for example, a price cap), a successful demand management program that causes a reduction in demand may result in less revenue for a distributor. A revenue cap avoids this.

We are also required to consider the effect of service classification on a distributor's incentive to adopt or implement efficient embedded generator connections.[193] We consider our proposed application of the DMIS meets this requirement as TasNetworks' standard control services will be under a revenue cap in the next regulatory control period.

Distributor's ability to offer efficient pricing structures

The rules also require us to consider the extent to which the distributor is able to offer efficient pricing structures in our design and implementation of a DMIS.[194] Efficient pricing structures reflect the true costs of supplying electricity at a particular part of the network at any given time. These tariff structures would price electricity highest during peak demand periods, reflecting the high costs of transporting energy when a network utilisation is at its highest. This price signal would discourage grid electricity usage at these times, lowering peak demand and adjusting network utilisation downwards.

The DMIA incentivises a distributor to trial measures that will assist the transition of networks to more efficient pricing. TasNetworks states that it structures its network tariffs to signal the impact customers have on the distribution network, manage demand and volume variance risk, and avoid sending signals that could result in inefficient choices being made by customers.[195] We note that the NER require distributors to

192 NER, clause 6.6.3(b)(2).

193 NER, clause 6.6.3(b)(6).

194 NER, clause 6.6.3(b)(3).

195 Aurora Energy, *Pricing Proposal, 1 July 2014 - 30 June 2015*, April 2014.

develop efficient tariff structures consistent with the pricing principles for direct control services set out in the rules.[196]

Interaction with our other incentive schemes

The DMIA intends to encourage businesses to investigate and implement innovative demand management strategies, regardless of their potential efficiency. In developing and implementing the DMIS in Tasmania, we must consider how it could potentially interact with our other incentive schemes.[197] Neither our expenditure incentive schemes (EBSS and CESS) nor STPIS intend to discourage a distributor from using its DMIA allowance.

While a distributor's annual opex allowance incorporates the DMIA allowances, we may exclude the DMIA from the EBSS.[198] Any potential substitution between opex and capex resulting from projects approved under the DMIA will be incentive-neutral as our proposed EBSS and CESS provide balanced incentives for opex and capex savings.

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196 NER, clause 6.18.1A. NER, clause 6.18.5.

197 NER, clause 6.6.3(b)(4).

198 Under the EBSS we can exclude any categories of opex not forecast using a single year revealed cost approach where it would better achieve the requirements (of the EBSS) under cl. 6.5.8 of the NER. DMIA projects are excluded from forecast opex so not considered to be forecast using a single year revealed cost approach. AER, *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, 29 November 2013.

4 Expenditure forecast assessment guideline

This attachment sets out our intention to apply our expenditure assessment guideline[199] including the information requirements to TasNetworks for the 2017–22 regulatory control period. We propose applying the guideline as it sets out our new expenditure assessment approach developed and consulted upon during the Better Regulation program. The expenditure forecast assessment guideline outlines for the distributor and interested stakeholders the types of assessments we will do to determine efficient expenditure allowances, and the information we require from the distributor to do so.

We were required to develop the guideline under the rules.[200] The expenditure assessment guideline is based on a nationally consistent reporting framework allowing us to compare the relative efficiencies of distributors and decide on efficient expenditure allowances. The rules require TasNetworks to advise us by 30 June 2015 of the methodology it proposes to use to prepare forecasts.[201] In the F&A we must advise whether we will deviate from the guideline.[202] This will provide clarity to TasNetworks on how we will apply the guideline and the information they should include in their regulatory proposals.

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

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

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

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

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

202 NER, clause 6.8.1(b)(2)(viii).

- cost benefit analysis and detailed project reviews.[203]

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

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

5 Depreciation

As part of the roll forward methodology, when the RAB is updated from forecast capex to actual capex at the end of a regulatory control period, it is also adjusted for depreciation. This attachment sets out our preliminary approach to calculating depreciation when the RAB is rolled forward to the commencement of the 2022–27 regulatory control period.

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

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

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

Consumers benefit from improved efficiencies through lower regulated prices. Where a CESS is applied, using forecast depreciation maintains the incentives for distributors to pursue capex efficiencies, whereas using actual depreciation would increase these incentives. There is more information on depreciation as part of the overall capex incentive framework in our capex incentives guideline.[204] In summary:

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

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

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

5.1 AER's preliminary position

Our preliminary position is to use the forecast depreciation approach to establish the RAB at the commencement of the 2022–27 regulatory control period for TasNetworks. We consider this approach will provide sufficient incentives for TasNetworks to achieve capex efficiency gains over the 2017–22 regulatory control period.

5.2 AER's assessment approach

We must decide for our determination whether we will use actual or forecast depreciation to establish a distributor's RAB at the commencement of the following regulatory control period.[205]

We are required to set out in our capex incentives guideline our process for determining which form of depreciation we propose to use in the RAB roll forward process.[206] Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:[207]

- 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.

205 NER, clause S6.2.2B.

206 NER, clause 6.4A(b)(3).

207 NER, clause S6.2.2B.

5.3 Reasons for AER's preliminary position

Consistent with our capex incentives guideline, we propose to use the forecast depreciation approach to establish the RAB at the commencement of the 2022–27 regulatory control period.

We had regard to the relevant factors in the rules in developing the approach to choosing depreciation set out in our capex incentives guideline.[208]

Our approach is to apply forecast depreciation except where:

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

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

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

We have chosen forecast depreciation as our default approach because, in combination with the CESS, it will provide a 30 per cent reward for capex underspends and 30 per cent penalty for capex overspends, which is consistent for all asset classes. In developing our capex incentives guideline, we considered this to be a sufficient incentive for a distributor to achieve efficiency gains over the regulatory control period in most circumstances.[209]

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

209 As noted in section 5.2. of this paper, the length of the regulatory control period has implications for the rewards and penalties available under incentive schemes.

The opening RAB for the 2017–22 period will be established using actual depreciation, as stated in our previous determination that applies to TasNetworks for the 2012–17 period. The use of forecast depreciation to establish the opening RAB for the 2022–27 period will therefore represent a change of approach. TasNetworks is not currently subject to a CESS but we propose to apply the CESS in the next regulatory control period. We discussed this in section 3.3.

For TasNetworks, at this stage, we consider the incentive provided by the application of the CESS in combination with the use of forecast depreciation and our other ex post capex measures should be sufficient to achieve the capex incentive objective.[210] Therefore, we do not see the need to apply actual depreciation at this time.

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

6 Jurisdictional and legacy issues

The rules do not limit the matters distributors may request the AER to amend in an F&A.[211] Similarly, we may make an F&A that extends beyond the matters specifically listed in the rules.[212] This attachment sets out our preliminary position on dual function assets and TasNetworks' regulatory control period.

6.1 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, our preliminary position is that we are not required to, and will not; make any determination under the rules regarding dual-function assets.[213]

6.2 Regulatory control period

TasNetworks is proposing to align the regulatory control periods of its distribution and transmission businesses through implementation of a two year regulatory control period for its distribution business instead of the five year period currently required by the rules.[214] TasNetworks has proposed a rule change to allow a two year regulatory control period commencing on 1 July 2017 and ending on 30 June 2019 for its distribution business.[215]

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211 NER, clause 6.8.1(c)(1).

212 NER, clause 6.8.1(g).

213 NER, clauses 6.8.1(b)(1)(ii) and 6.25(b).

214 NER, clause 6.3.2(b).

215 See http://www.aemc.gov.au/Rule-Changes/Aligning-TasNetworks'-Regulatory-Control-Periods.

The AEMC is assessing this request as a non-controversial rule under its expedited rule making process and, subject to any submissions objecting to an expedited process, will publish a final rule determination by 9 April 2015. The AEMC has canvassed other options to align the regulatory control periods of TasNetworks' distribution and transmission businesses. These involve setting a three year regulatory control period for its transmission business or a seven year regulatory control period for its distribution business.

The length of TasNetworks' regulatory control period will impact on the application of our incentives schemes and future processes regarding the F&A.

The length of the regulatory control period has implications for the strength of incentives for efficient expenditure over the period, with shorter periods tending to lessen incentives for efficient expenditure. Also our incentive schemes for operating (EBSS) and capital (CESS) expenditure are designed to operate over a five-year period with the length of the period impacting on the proportion of efficiency gains and losses that is shared between a distributor and its customers.

A two year regulatory control period commencing on 1 July 2017 and ending on 30 June 2019 would result in the F&A consultation process for the 2019-24 regulatory control period commencing in November 2016, before our final determination in April 2017 for the 2017-19 regulatory control period. Therefore the next F&A consultation process would commence sixteen months after this current F&A process concludes, and prior to implementation of the 2017 determination applying the new F&A.

The AER has not objected to TasNetworks' rule change request. Subject to the outcome of this request we will consider the impact of a shorter regulatory control period for the operation of our incentive schemes, the next F&A process and any other relevant matters.

Appendix A: Rule requirements for classification

We must have regard to four factors when classifying distribution services.[216]

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

   - the presence and extent of any barriers to entry in a market for electricity network services
   - the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other electricity network service provided by the network service provider
   - the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other service provided by the network service provider in any other market
   - the extent to which any market power possessed by a network service provider is, or is likely to be, mitigated by any countervailing market power possessed by a network service user or prospective network service user
   - the presence and extent of any substitute, and the elasticity of demand, in a market for an electricity network service in which a network service provider provides that service
   - the presence and extent of any substitute for, and the elasticity of demand in a market for, elasticity or gas (as the case may be)
   - the extent to which there is information available to a prospective network service user or network service user, and whether that information is adequate, to enable the prospective network service user or network service user to negotiate on an informed basis with a network service provider for the provision of an electricity network service to them by the network service provider.[217]

[216] NER, clause 6.2.1(c).

[217] NEL, s. 2F.

2. the form of regulation (if any) previously applicable to the relevant service or services, and, in particular, any previous classification under the present system of classification or under the present regulatory system (as the case requires)[218]

3. the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)[219]

4. any other relevant factor.[220]

The rules specify additional requirements for services we have regulated before.[221] They are:

1. There should be no departure from a previous classification (if the services have been previously classified); and

2. If there has been no previous classification - the classification should be consistent with the previously applicable regulatory approach.

We must have regard to six factors when classifying direct control services as either standard control or alternative control services.[222]

1. the potential for development of competition in the relevant market and how the classification might influence that potential

2. the possible effects of the classification on administrative costs of us, the distributor and users or potential users

3. the regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made

4. the desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction)

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218 NER, clause 6.2.1(c)(2).

219 NER, clause 6.2.1(c)(3).

220 NER, clause 6.2.1(c).

221 NER, clause 6.2.1(d).

222 NER, clause 6.2.2(c).

5. the extent that costs of providing the relevant service are directly attributable to the customer to whom the service is provided, and

6. any other relevant factor.[223]

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

223 NER, clause 6.2.2(c).

Appendix B – Classification of Tasmanian electricity distribution services

Service group	AER's proposed classification 2017-22	Current classification 2012-17
AER service group—network services		
Planning the distribution network	Standard control	Standard control
Designing the distribution network	Standard control	Standard control
Constructing the distribution network	Standard control	Standard control
Maintaining the distribution network and connection assets	Standard control	Standard control
Operating the distribution network and connection assets for DNSP purposes	Standard control	Standard control
Administrative support (call centre, network billing, etc)	Standard control	Standard control
Emergency response	Standard control	Standard control
Emergency response - Emergency recoverable works	Unclassified	Standard control

Service group	AER's proposed classification 2017-22	Current classification 2012-17
AER service group—connection services		
Standard connection services	Standard control	Standard control
Connections requiring augmentation	Standard control	Standard control
AER service group—metering services		
Standard metering services for type 5-7 meters	Alternative control	Alternative control
Special meter readings and meter testing of type 5-7 meters	Alternative control	Alternative control
PAYG metering services provided by Aurora Retail	Unclassified	Unclassified
AER service group—public lighting services		
Repair, replacement and maintenance of public lighting	Alternative control	Alternative control
Provision of new public lighting assets	Alternative control	Alternative control
New public lighting technology services	Negotiated	Negotiated

Service group	AER's proposed classification 2017-22	Current classification 2012-17
AER service group—ancillary services		
Energisation, de-energisation and re-energisation (includes disconnections and reconnections)	Alternative control (fee based)	Alternative control (fee based)
Meter alteration (adding and altering circuits)	Alternative control (fee based)	Alternative control (fee based)
Meter testing (including for single phase, three phase and current transformer meters)	Alternative control (fee based)	Alternative control (fee based)
Removal of meters and service connection	Alternative control (fee based)	Alternative control (fee based)
Renewable energy connection – including installation of import/export metering equipment	Alternative control (fee based)	Alternative control (fee based)
Temporary connections	Alternative control (fee based)	Alternative control (fee based)
Disconnect service connection	Alternative control (fee based)	Alternative control (fee based)
Truck tee up	Alternative control (fee based)	Alternative control (fee based)
Open turret or cabinet for electrical contractor	Alternative control (fee based)	Alternative control (fee based)

Service group	AER's proposed classification 2017–22	Current classification 2012–17
AER service group—ancillary services		
Moving mains, services or meters forming part of the network to accommodate extension, redesign or redevelopment of any premises	Alternative control (quoted)	Alternative control (quoted)
The provision of electric plant for the specific provision of top-up or stand-by supplies of electricity	Alternative control (quoted)	Alternative control (quoted)
Temporary supply	Alternative control (quoted)	Alternative control (quoted)
Reserve or duplicate supply	Alternative control (quoted)	Alternative control (quoted)
Network services and system augmentation required to receive energy from an embedded generator	Alternative control (quoted)	Alternative control (quoted)
Alteration and relocation of existing public lighting assets	Alternative control (quoted)	Alternative control (quoted)

Appendix C: Shortened forms

Shortened Form	Extended Form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CESS	capital expenditure sharing scheme
CPI	consumer price index
CPI-X	consumer price index minus X
current regulatory control period	1 July 2012 to 30 June 2017
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUOS	distribution use of system
EBSS	efficiency benefit sharing scheme
expenditure assessment guideline	expenditure forecast assessment guideline for electricity distribution
GSL	guaranteed service level
F&A	Framework and approach
kWh	kilowatt hours

MAR	maximum allowable revenue
NECF	National Energy Customer Framework
NEM	National Electricity Market
NEO	National Electricity Objective
NER or the rules	National Electricity Rules
next regulatory control period	1 July 2017 to 30 June 2022
NUOS	network use of system
NSW	New South Wales
opex	operating expenditure
RAB	regulatory asset base
ROLR	retailer of last resort
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCER	Standing Council on Energy and Resources
STPIS	service target performance incentive scheme
Tas	Tasmania
WAPC	weighted average price cap