



Framework and approach for TasNetworks Distribution

for the
Regulatory control period commencing 1 July 2017

July 2015

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Contents

About the framework and approach	7
Part A: Overview	9
Classification of distribution services	9
Direct control services	10
Standard control services	11
Alternative control services	11
Negotiated distribution services	12
Unclassified (unregulated)	12
Control mechanisms	13
Incentive schemes	14
Service target performance incentive scheme	15
Efficiency benefit sharing scheme.....	15
Capital expenditure sharing scheme	15
Demand management incentive scheme	15
Small-scale incentive scheme.....	16
Application of the expenditure forecast assessment guideline	16
Depreciation	17
Jurisdictional and legacy issues	17
Dual function assets	17
Regulatory control period	17
Part B: Attachments	19
1 Classification of distribution services	20
1.1. AER's proposed approach	22
1.1.1 Network services.....	23
1.1.2 Metering services	24

1.1.3	Public lighting services	24
1.1.4	Connection services	24
1.1.5	Ancillary network services (fee based services)	25
1.1.6	Ancillary network services (quoted services)	25
1.2.	AER's assessment approach	25
1.3.	Reasons for AER's proposed approach	26
1.3.1	Network services	26
1.3.2	Metering services	28
1.3.3	Public lighting	31
1.3.4	Connection services	35
1.3.5	Ancillary network services (fee based and quoted services)	41
1.4.	AER's proposed approach to service classification	42
2	Control mechanisms	43
2.1.	AER's decision	43
2.2.	AER's assessment approach	43
2.2.1	Standard control services	45
2.2.2	Alternative control services	47
2.3.	AER's reasons — control mechanism and formulae for standard control services	47
2.3.1	Efficient tariff structures	48
2.3.2	Administrative costs	49
2.3.3	Existing regulatory arrangements	50
2.3.4	Desirability of consistency between regulatory arrangements	50
2.3.5	Revenue recovery	50
2.3.6	Pricing flexibility	50
2.3.7	Pricing stability	51
2.3.8	Incentives for demand side management	52
2.3.9	Hybrid form of control	52

2.3.10	Formulae for control mechanism	53
2.4.	AER's reasons — control mechanism for alternative control services	54
2.4.1	Influence on the potential to develop competition	55
2.4.2	Administrative costs	55
2.4.3	Existing regulatory arrangements	55
2.4.4	Desirability of consistency between regulatory arrangements	56
2.4.5	Cost reflective prices	56
2.4.6	Formulae for alternative control services	56
3	Incentive schemes	58
3.1.	Service target performance incentive scheme	58
3.1.1	AER's proposed approach	59
3.1.2	AER's assessment approach	60
3.1.3	Reasons for AER's proposed approach	61
3.2.	Efficiency benefit sharing scheme	65
3.2.1	AER's proposed approach	65
3.2.2	AER's assessment approach	66
3.2.3	Reasons for AER's proposed approach	66
3.2.4	Two year regulatory control period	69
3.3.	Capital expenditure sharing scheme	70
3.3.1	AER's proposed approach	70
3.3.2	AER's assessment approach	70
3.3.3	Reasons for AER's proposed approach	71
3.4.	Demand management incentive scheme	72
3.4.1	AER's proposed approach	73
3.4.2	AER's assessment approach	73
3.4.3	Reasons for AER's proposed approach	74
4	Expenditure forecast assessment guideline	76

5	Depreciation	78
5.1.	AER's proposed approach	78
5.2.	AER's assessment approach.....	79
5.3.	Reasons for AER's proposed approach	79
6	Jurisdictional and legacy issues.....	81
6.1.	Dual function assets.....	81
6.2.	Regulatory control period	81
6.2.1	Incentive schemes	81
6.2.2	Framework and approach 2019-24.....	82
	Appendix A: Rule requirements for classification	83
	Appendix B – Classification of Tasmanian electricity distribution services	
	85	
	Appendix C: Shortened forms	88
	Appendix D - Submitters to preliminary positions paper	90

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).¹ 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 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 proposed approach on which services we will regulate and how we propose to apply the relevant incentive schemes. It also 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.

In April 2015 we decided to replace the current Tasmanian F&A for the next regulatory control period. This decision arose following consultation with stakeholders.² Our main reason for this decision was because of significant changes to the rules to introduce new incentive schemes and revised regulatory requirements, making elements of the current F&A no longer relevant. TasNetworks sought a new or amended F&A. Submissions received also supported the amendment or replacement of the current F&A. 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 two year regulatory control period³ commencing 1 July 2017 and sets out our proposed approach 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

¹ In addition to regulating NEM transmission and distribution, we regulate the NEM wholesale market and administer the National Gas Rules.

² NER, clauses 6.8.1(c)(1)–(3).

³ The AEMC published a final rule determination on 9 April 2015 allowing TasNetworks a two year regulatory control period commencing on 1 July 2017 and ending on 30 June 2019 for its distribution business.

- 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.

Before reaching our proposed approach, we published a preliminary positions F&A on 2 April 2015, seeking submissions from interested parties. Submissions closed on 15 May 2015, with 6 responses received. We also consulted our Consumer Challenge Panel (CCP). Submissions and CCP views have been considered in reaching our decisions and proposed approaches set out in this F&A. A list of submitters is included at appendix D. Submissions are available on the AER's website.

We will use the pre-lodgement process which follows the F&A process to continue discussions with TasNetworks about the treatment of confidential information as set out in our confidentiality guideline.⁴ 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.⁵

Table 1 summarises the Tasmanian distribution determination process.

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	9 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.

⁴ AER, Confidentiality guideline, 19 November 2013.

⁵ AER, Consumer engagement guideline for network service providers, 6 November 2013.

Part A: Overview

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

- classification of distribution services (which services we will regulate)
- control mechanisms (how we will determine prices for regulated services) and the formulae that give effect to the control mechanisms
- 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.

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 ⁶ or services that are contestable.	We have no role in regulating these services.

Source: AER

The classification of TasNetworks' distribution services will not change significantly for the 2017–19 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.

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

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

services as direct control services. That is, we will directly set prices distributors will charge customers, or set revenues distributors may recover from customers.⁷

Most distribution services fall within the network services group, which includes poles, wires, and other core infrastructure of a distribution business.⁸ 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 proposed approach 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 (excluding new public lighting technology services) 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 proposed approach 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.

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 (excluding new public lighting technology services), because a defined group of customers purchase these services, for example, local councils.

⁷ 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).

⁸ Appendix B sets out TasNetworks' distribution services in more detail.

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 proposed approach is to continue to classify services to install new public lighting technologies as negotiated distribution 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.

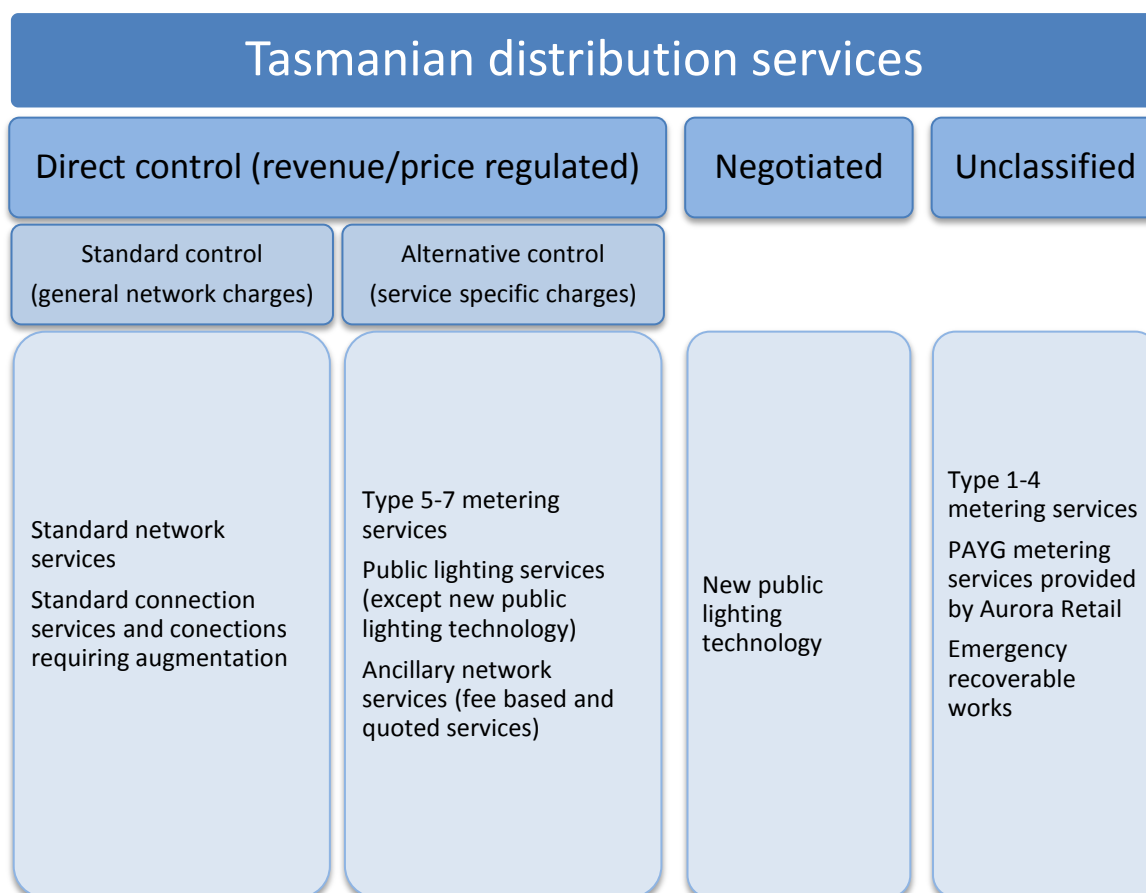
Our position is to not classify emergency recoverable works.⁹ This will create the right incentives for TasNetworks Distribution to recover the cost of emergency works recoverable from third parties that cause damage to the network.

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.

We use the above service classifications throughout this F&A. Figure 1 sets out our proposed approach to classification of Tasmanian distribution services.

⁹ 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.

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



Source: AER

Control mechanisms

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

The rules require us to decide the control mechanism forms¹² 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.¹³ These include price schedules, caps on the prices of individual services, weighted average price caps, revenue caps, average revenue caps and hybrid control mechanisms.

¹⁰ NER, clause 6.2.5(a).

¹¹ NER, clause 6.12.3(c).

¹² NER, clause 6.2.5(b).

¹³ NER, clause 6.2.5(b).

In deciding on the form of control mechanism, the rules require us to have regard to specified factors.¹⁴ These include the need for efficient tariffs, administrative costs, previous regulatory arrangements and consistency. In light of these considerations, our position on the form of control mechanisms for TasNetworks' standard control and alternative control services is:

- 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. For alternative control services charged on a quoted basis, we will adopt a cost build up approach.

For standard control services, the rules mandate the basis of the control mechanism must be the prospective CPI–X form, or some incentive-based variant.¹⁵ For alternative control services, we will confirm a control mechanism basis through the distribution determination process.

Incentive schemes

The purpose of incentive schemes is to encourage distributors to manage their businesses in a safe, reliable manner that serves the long term interests of consumers. The schemes provide distributors with incentives to only incur efficient costs and to meet or exceed service quality targets. In some instances, distributors may incur a financial penalty if they fail to meet set targets. These schemes include the service target performance incentive scheme, efficiency benefit sharing scheme, capital expenditure sharing scheme and demand management incentive scheme. The overall objectives of the schemes are to:¹⁶

- 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)

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

¹⁵ NER, clause 6.2.6(a). The basis of the form of control is the method by which target revenues or prices are calculated e.g. a building block approach.

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

- share efficient improvements and losses between distributors and consumers.

We outline below our proposed approach 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.

Our proposed approach 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.¹⁷ 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 proposed approach 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 proposed approach 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

¹⁷ OTTER, Guideline - Guaranteed Service Level Scheme, December 2007.

distributors to lower or shift the demand for standard control services is incentivised through our demand management incentive scheme (DMIS).

Our proposed approach is to continue to apply the DMIS to TasNetworks for the next regulatory control period. As we intend that TasNetworks' standard control services will operate under a revenue cap, we only apply Part A of the DMIS. That is, a demand management innovation allowance (DMIA). The DMIS adds an innovation allowance to 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. For the next regulatory control period, the allowance will be determined as part of our revenue determination.

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.¹⁸ The requests are in response to recommendations made by the AEMC in its Power of Choice review.¹⁹ On 28 May 2015 the AEMC released its draft determination in response to the rule change requests. The draft determination includes a requirement for the AER to develop and publish a new DMIS in accordance with the distribution consultation procedures by 1 December 2016. Subject to the AEMC's final determination we intend to apply a new DMIS to TasNetworks for the 2019-24 regulatory control period. Our proposed approach is to continue to apply the current DMIS to TasNetworks for the 2017-19 regulatory control period.

Small-scale incentive scheme

The rules state that we may develop a small-scale incentive scheme.²⁰ As we have not developed this scheme, our proposed approach is not to apply such a scheme to TasNetworks in the next regulatory control period.

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 proposed approach 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.

¹⁸ AEMC, Consultation paper, National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015, 19 February 2015. <http://www.aemc.gov.au/Rule-Changes/Demand-Management-Embedded-Generation-Connection-I#>.

¹⁹ AEMC, Final report, Power of choice review – giving consumers' choice in the way they use electricity, 30 November 2012.

²⁰ 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 2019–2024 regulatory control period. Our proposed approach is to use forecast depreciation to establish the RAB as at 1 July 2019.

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

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

Jurisdictional 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 decision is that we are not required to, and will not, make any determination under the rules regarding dual-function assets.²¹

Regulatory control period

In October 2014 TasNetworks 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. TasNetworks proposed 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 required by the rules.²²

The AEMC assessed this rule change request and published a final rule determination on 9 April 2015 accepting TasNetworks' proposal.

The AER will give consideration to the impact of a shorter regulatory control period for the operation of incentive schemes as part of our revenue determination. For example, the EBSS (version 2) we propose to apply to the 2017-19 regulatory control period allows

²¹ NER, clauses 6.8.1(b)(1)(ii) and 6.25(b).

²² NER, clause 6.3.2(b).

flexibility in the length of the carryover period where the length of the regulatory control period is not five years.

A two year regulatory control period commencing on 1 July 2017 and ending on 30 June 2019 results in the F&A consultation process for the 2019-24 regulatory control period commencing before our final revenue determination in April 2017 for the 2017-19 regulatory control period. Therefore, consideration of whether it is necessary or desirable to replace or amend this F&A would commence prior to implementation of the 2017-19 determination applying this F&A. While we do not anticipate that it will be necessary or desirable to replace or amend this F&A for the 2019-24 regulatory control period, we will consult publicly on this in November 2016 as required under the Rules.²³

²³ NER, cl. 6.8.1(a)(2).

Part B: Attachments

1 Classification of distribution services

This attachment sets out our proposed approach to 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 prices²⁴
- allow parties to negotiate services and prices and only arbitrate disputes if necessary, or
- do not regulate at all.

If we control prices directly, classification further determines whether a distributor recovers service costs from all customers or only those benefiting directly from specific services.²⁵

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.

Service classifications must be as set out in this F&A unless we consider unforeseen circumstances justify us departing from these classifications.²⁶

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.²⁷ 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'.²⁸

²⁴ 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.

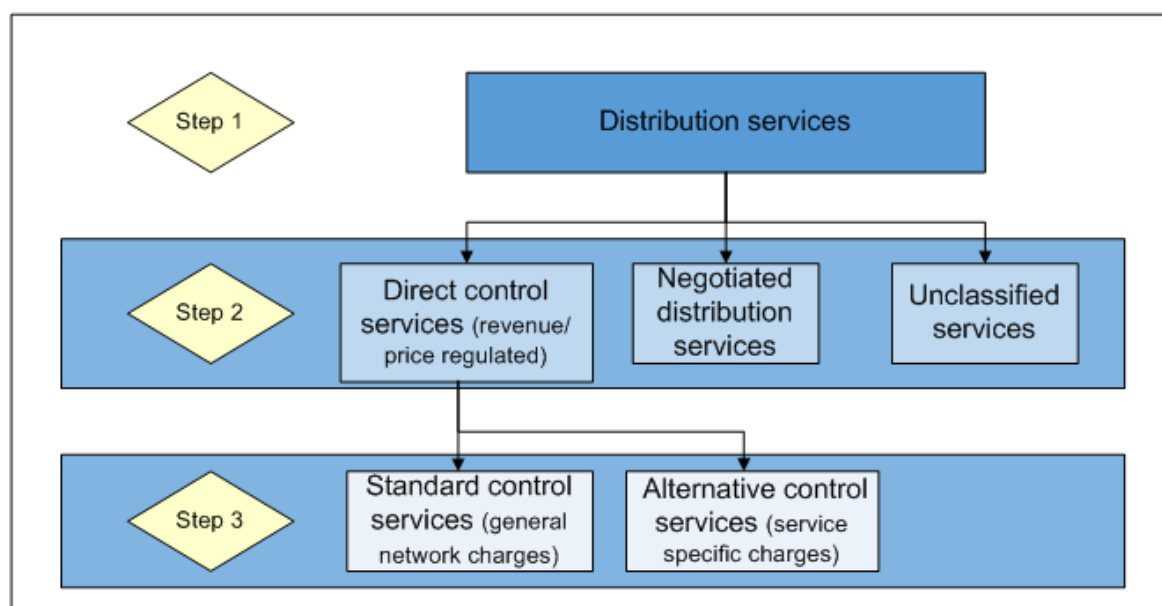
²⁵ Standard control service costs are generally recovered through distribution use of service tariffs paid by all, or most, customers. Alternative control or negotiated service costs are generally recovered from individual customers receiving them.

²⁶ NER, clause 6.12.3(b).

²⁷ NER, chapter 10, glossary.

²⁸ NER, chapter 10, glossary.

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

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

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

1.1 AER's proposed approach

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

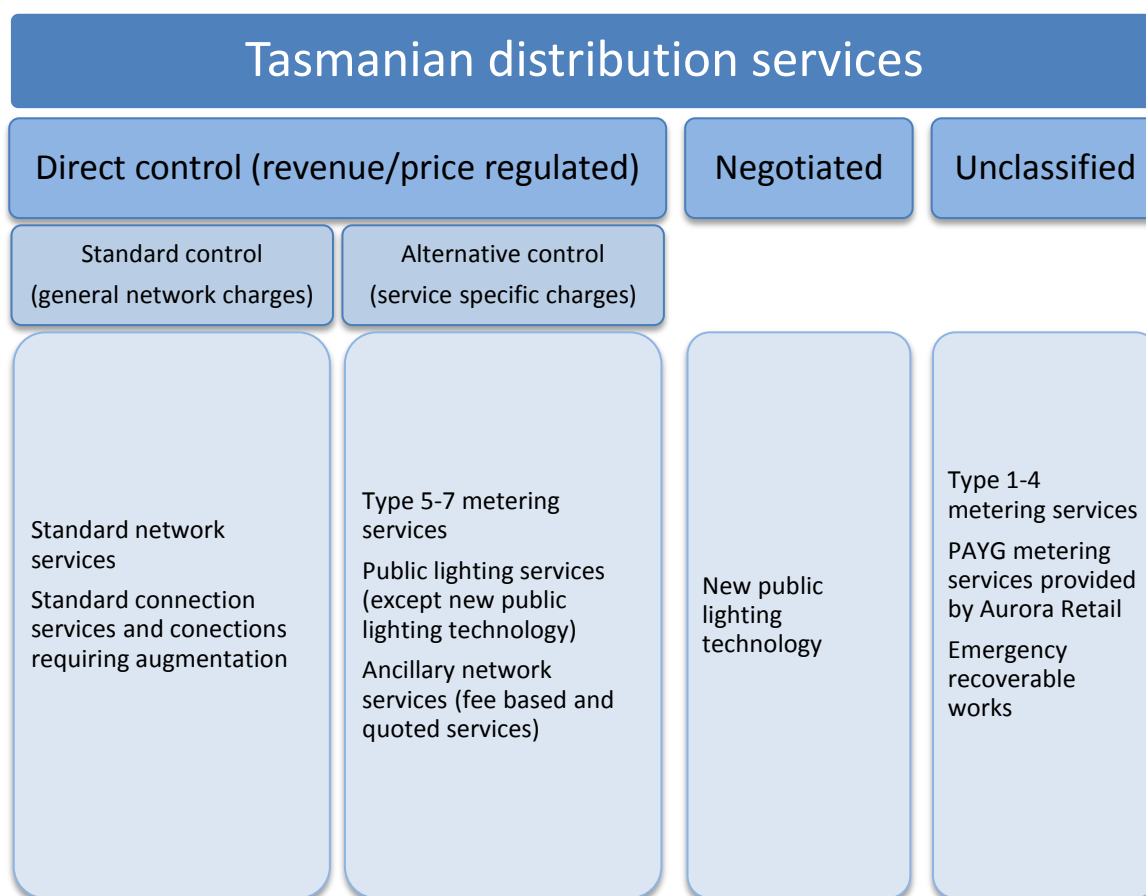
- network services
- metering services
- public lighting services
- connection services
- ancillary network services (fee based and quoted services).

We consider that each service falling within the above service groups is a distribution service.²⁹ They are services provided by means of, or in connection with, a distribution service.³⁰ Figure 3 summarises our proposed classification of TasNetworks' distribution services. Appendix B provides a more detailed breakdown of the proposed service classifications.

²⁹ See Appendix B for a list of each distribution service falling within the groups set out above.

³⁰ NER, chapter 10, 'distribution system'.

Figure 3: AER proposed classification of Tasmanian distribution services



Source: AER

The following section summarises our proposed approach on the classification of each service group.

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.³¹

Proposed rule changes currently under consideration by the AEMC would facilitate the competitive provision of metering and related services in the future.³² The AEMC's final determination is expected on 26 November 2015.

We may refine our approach to classification of metering services in Tasmania if this is necessary to achieve a position consistent with the rule changes ultimately applied there. 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.

Our proposed approach is to retain the current classifications for public lighting services.

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.

Our proposed approach is to retain the current classification for standard connection services and connections requiring augmentation.

³¹ 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.

³² See <http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv>.

1.1.5 Ancillary network services (fee based 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 proposed approach is to retain the current alternative control service classification for fee based services.

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

1.1.6 Ancillary network services (quoted 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 'quoted services' group 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 a distributor 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.³³ We have reproduced these at appendix A. They include the presence or extent of barriers to entry by alternative providers and whether a distributor has 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.³⁴

For services we intend to classify as direct control services, the rules require us to have regard to a further range of factors.³⁵ These include the potential to develop competition in provision of a service and how our classification may influence that potential. Also, whether

³³ NEL, clause 6.2.1(c); NEL, s. 2F.

³⁴ NEL, clause 6.2.1(c).

³⁵ NEL, clause 6.2.2(c).

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:³⁶

- 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.³⁷

1.3 Reasons for AER's proposed approach

This section sets out our proposed approach and reasons for the classifications we propose for:

- network services
- metering services
- public lighting services
- 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.³⁸ Customers use or rely on network services on a daily basis. Network services include the construction and maintenance of the shared network.

Our proposed approach 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 licence 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.³⁹ Therefore, we consider that there is no market for network services for third parties to compete in.

³⁶ NER, clause 6.2.2(d).

³⁷ NER, clauses 6.2.1(d) and 6.2.2(d).

³⁸ NER, chapter 10, definition of 'network service'.

³⁹ This is relevant under the form of regulation factors; see NEL, s. 2F(a).

TasNetworks possesses significant market power due to the regulatory arrangements in place.⁴⁰ As such, we propose to classify network services as direct control services.

We must further classify direct control services as either standard or alternative control services.⁴¹ Our proposed approach 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.⁴² There would be no material effect on administrative costs for us, TasNetworks, users or potential users.⁴³ This is because classifying 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.⁴⁴ Further, a distributor provides network services through a shared network and therefore cannot directly attribute the costs of these services to individual customers.⁴⁵

Emergency recoverable works

Emergency works are services related 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.⁴⁶

When network assets are damaged distributors carry out emergency works as part of maintenance and repair activities 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 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 party responsible for causing the damage, through the courts if necessary.

The Consumer Challenge Panel submitted:

The AER nominates emergency recoverable works should be excluded from regulated and negotiated services. CCP4 agrees. By definition, the term recoverable services implies that TasNetworks Distribution should be able to get restitution from the causers of the need for the emergency recoverable service. By excluding the service from direct control and negotiated services, this imposes on TasNetworks Distribution a requirement

⁴⁰ This is a relevant form of regulation factor: NEL, s. 2F(d).

⁴¹ NER, clause 6.2.2(c).

⁴² NER, clause 6.2.2(c)(1).

⁴³ NER, clause 6.2.2(c)(2).

⁴⁴ NER, clause 6.2.2(c)(3).

⁴⁵ NER, clause 6.2.2(c)(5).

⁴⁶ Emergency recoverable works are a component of TasNetworks' 'emergency response' services.

to seek restitution from the causer of the need for the service rather than having electricity consumers pay for such works.⁴⁷

TasNetworks submitted:

Where a third party causes damage to the network, TasNetworks' customers should rightly expect that TasNetworks repair that network and where possible pass on those costs to the party that causes the damage. Equally, where a third party damages the network and is not identifiable, the network should be repaired by TasNetworks but the costs should be spread across those benefiting from the repair – the general customer base.⁴⁸

We propose to continue classifying emergency response and related works as direct control standard control services but not classify emergency recoverable works.⁴⁹ By not classifying emergency recoverable works, TasNetworks is not able to recover costs for emergency response and related works from consumers as a whole where these costs are recoverable from the party responsible for causing the damage. 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 proposed approach to this issue is consistent with our approach to the classification of emergency recoverable works in NSW, Queensland⁵⁰ and Victoria.⁵¹

1.3.2 Metering services

All electricity customers have a meter that measures the amount of electricity they use.⁵² 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—that is, they are generally 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 provider of type 5 (interval) and 6 (accumulation) meters in Tasmania.⁵³ Type 6 meters record total electricity

⁴⁷ Consumer Challenge Panel sub Panel CCP4 - Submission to framework and approach preliminary positions paper - 13 May 2015, p.3.

⁴⁸ TasNetworks - Submission to framework and approach preliminary positions paper - 15 May 2015, pp. 7-8.

⁴⁹ NER, clause 6.2.1(c)(4).

⁵⁰ 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.

⁵¹ AER, Final Framework and approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016, October 2014.

⁵² All connections to the network must have a metering installation (NER, clause 7.3.1A(a)).

⁵³ TasNetworks is the 'responsible person' for type 5, 6, and 7 metering installations (NER, clause 7.2.3(a)(2)).

usage over a period of time. Type 5 meters can record electricity usage and time of use.⁵⁴ 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).⁵⁵ 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 by calculating 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.

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.⁵⁶ 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' existing type 5-7 metering services, for which meter reading and testing services are undertaken.⁵⁷ 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 proposed approach is that a different classification of these metering services is not clearly more appropriate⁵⁸ 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.⁵⁹ For this reason, our proposed approach is not to classify these services. This is consistent with the current regulatory approach in Tasmania and in most other jurisdictions.⁶⁰

⁵⁴ Interval meters record electricity usage every 30 minutes.

⁵⁵ NER, clause 7.2.3(a)(2).

⁵⁶ NER, clause 6.2.1.

⁵⁷ NEL, s. 2F(a) and (d).

⁵⁸ NER, clause 6.2.2(d).

⁵⁹ 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)).

⁶⁰ 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,

Pay as you go metering services

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.

Expanding competition in metering and related services

Currently, competition in metering is limited to large customers (i.e. type 1-4 metering) in the national electricity market while regulated distributors have the sole responsibility to provide small customers with metering services.⁶¹

The AEMC is undertaking a rule change process to expand competition in metering and related services to help facilitate a market led roll out of advanced metering technology, following proposals from the COAG Energy Council. The increased availability of advanced meters will enable the introduction of more cost reflective network prices and allow consumers to make more informed decisions about how they want to use energy services. The AEMC has proposed that metering costs be unbundled from shared network charges.⁶² Also, that provision of metering services be contestable and not be a monopoly service exclusively provided by distributors. The AEMC published its draft rule on 26 March 2015.⁶³ The final rule determination is expected to come into effect from 1 December 2017.

Vector Limited's submission⁶⁴ commented on barriers to competition in the metering market, noting the impact of exit and administration fees levied by distributors on market entry by alternative metering service providers. Regarding these issues, Vector Limited supported the regulatory approach we adopted in determinations for distributors in NSW and ACT for the 2015–19 regulatory control period, noting:

Again, it is reasonable to expect that the AER will apply to TasNetworks settings similar to those it applied to NSW and ACT distributors for the next regulatory control period. These settings provide potential investors the right incentives to enter the metering market in Tasmania.⁶⁵

TasNetworks' submission to the AEMC's draft rule on meter competition did not support implementation of the draft rule in Tasmania at this time. TasNetworks submitted:

There are significant differences between Tasmania's circumstances and those of other jurisdictions within the national electricity market (NEM) which make the implementation of competitive metering and related services less likely to deliver the desired benefits to residential and small business customers. Therefore, unless major changes in market

⁶¹ Regulatory control period commencing 1 January 2016, October 2014.

⁶¹ NER clause 7.2.3(a). Small customers refers to any customer with less than 160MWh annual consumption (effectively all residential and small business customers fall into this category).

⁶² AEMC, Power of choice review – giving consumers options in the way they use electricity – final report, November 2012, p. 83.

⁶³ AEMC, Draft rule determination: Expanding competition in metering and related services, 26 March 2015.

⁶⁴ Vector Limited - Submission to framework and approach preliminary positions paper - 15 May 2015.

⁶⁵ Vector Limited - Submission to framework and approach preliminary positions paper - 15 May 2015, p.4.

conditions occur, the Tasmanian market should be excluded, at least initially, from the implementation of the draft rule.⁶⁶

While we do not determine the contestability of metering services through our F&A process, our proposed 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 proposed approach is therefore consistent with the AEMC's draft rule which promotes the unbundling of metering costs and services from network services.⁶⁷ 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. In NSW and ACT 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. Our general approach to classification of metering services in Tasmania is consistent with the approach we have taken in NSW and ACT—that is, type 5, 6 and 7 metering services are broadly classified as alternative control services. We may refine our approach to classification of metering services in Tasmania if this is necessary to achieve a position consistent with the rule changes ultimately applied there.

1.3.3 Public lighting

TasNetworks operates and maintains the public lighting system throughout Tasmania on behalf of 28 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.⁶⁸ 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 of 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 not supplied by

⁶⁶ TasNetworks - Expanding Competition in Metering and Related Services Draft Rule (ERC0169) - Submission to AEMC, 21 May 2015.

⁶⁷ AEMC, Draft rule determination: Expanding competition in metering and related services, 26 March 2015.

⁶⁸ 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 as alternative control services has increased the potential and demand for supply arrangements by other parties.

New technologies are producing luminaires which are significantly more energy efficient, using less electricity than older public lighting assets. 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 TasNetworks may decide to supply such new technologies, such as LED lights, as part of their standard suite of public lighting services in the future. Such technologies can offer cost savings or improved service quality which local councils value as a benefit for their ratepayers.

In our F&A preliminary positions paper we proposed to retain the current classifications for public lighting services in Tasmania. We sought further views on the classification of these services and whether all public lighting services in Tasmania could be classified as negotiated services. Having considered submissions we propose to retain the current classifications of public lighting services. Our reasons are set out below.

Public lighting services (excluding new public lighting technology services)

Our proposed approach 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.

TasNetworks and Meander Valley Council both supported less regulation of public lighting services in Tasmania.

Meander Valley Council submitted:

Some parts of the Tasmanian public lighting market are already competitive, and the prices charged by TasNetworks for new lighting technologies are being set outside of the AER's pricing determination process. New technologies are likely to make up an increasing component of the installed base of public lighting, such is the pace of development, and the market conditions which once might have justified regulating the prices of the existing public lighting fleet are disappearing.

Classifying all public lighting as Unregulated Services will enable efficient choices to be made by customers with regard to the lighting technology and the service providers they use. Therefore, Meander Valley Council supports TasNetworks' proposal for the reclassification of public lighting services as an Unregulated Service.⁶⁹

TasNetworks submitted:

Technological change and a desire to reduce costs have meant that many recipients of the TasNetworks-provided public lights are investigating the means to undertake the provision of these services in their own right. Some councils and other road authorities are considering new technologies that were not envisaged as recently as three years ago. TasNetworks has already negotiated with two large local government authorities for these authorities to undertake the provision, maintenance and operation of some public

⁶⁹ Meander Valley Council - Submission to framework and approach preliminary positions paper - 19 May 2015, p.2.

lighting services in their areas. Other local government authorities are now seeking to do the same in their areas.

This change has meant that TasNetworks is no longer the sole provider of these services and no longer has a monopoly over the provision of all public lighting services. Public lighting services can be considered an activity where bilateral negotiation can produce more efficient, customer-focussed outcomes. The service classification should reflect this environment and, as an authority is able to negotiate the service model for lights within their area, those services should be treated as negotiated services.⁷⁰

While TasNetworks does not have a legislative monopoly over public lighting services, we consider that a monopoly position exists to a large extent for services provided through public lighting assets currently in place.⁷¹ TasNetworks currently owns the majority of public lighting assets⁷² and other parties also 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.

The Tasmanian Local Government Association submitted:

The challenge for local government more broadly, is that there is significant variation in the capacity of Tasmanian Councils to undertake a negotiation process around public lighting as well as significant variation in 'negotiating power' with the Distribution and Network Provider. In particular, smaller regional Councils may be particularly vulnerable from both an inequitable negotiation position (due to reduced volume of lights, geographic isolation and resourcing capacity) as well as an inability to bear the potential costs associated with an inability to reach agreement and ongoing mediation.⁷³

And:

The existence of regulation provides a safety net and risk management for councils, in what is essentially a monopoly market. This is particularly poignant to smaller councils in regional areas. As noted earlier, a market based model works where there is a balance of power in negotiations. In an unregulated model where there is only a single provider, disagreements or inability to reach agreement would be decided in arbitration and potentially have significant cost impacts for councils.

While it can be argued that removal of regulation may increase the chances of competition for the provision of network and distribution services in Tasmania, the market is comparatively small and it is unclear whether interest from other providers is likely.⁷⁴

The Consumer Challenge Panel submitted:

⁷⁰ TasNetworks - Submission to framework and approach preliminary positions paper - 15 May 2015, p.7.

⁷¹ NEL, s. 2F(d).

⁷² NEL, s. 2F(a).

⁷³ Tasmanian Local Government Association - Submission to framework and approach preliminary positions paper - 1 July 2015, p.5.

⁷⁴ Tasmanian Local Government Association - Submission to framework and approach preliminary positions paper - 1 July 2015, pp.5-6.

Some of the local councils, along with TasNetworks Distribution, have sought for general public lighting to be a negotiated service rather than an alternative control service. In general, CCP4 considers that retaining public lighting as an alternative control service is probably in the interests of consumers as it provides certainty and a limitation on the ability of TasNetworks Distribution to exercise the monopoly power it has in relation to the general activities in relation to public lighting.⁷⁵

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 Our proposed approach is to classify public lighting services, excluding new technology services, as direct control services.⁷⁷ As direct control services, we must further classify public lighting services as either standard control or alternative control services.⁷⁸ Our proposed approach 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 through new public lighting technologies 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 councils⁷⁹ and 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 to customers of the costs and certainty of the charges of providing public lighting services which may encourage other potential service providers to enter the market. 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.⁸⁰

As a price cap form of control is to be applied to public lighting services, TasNetworks can charge below the cap in response to customer pressure, but is not required to. Therefore there is scope for flexibility in charges levied by TasNetworks for public lighting services classified as alternative control services and subject to a price cap. We recognise that 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 based on submissions there does not appear to be an effective market for the majority of public lighting services in Tasmania as these services are supplied predominantly under monopoly conditions by TasNetworks. The ability of local councils to negotiate with TasNetworks appears quite uneven given their varying size and resources. Some of the larger councils will be in a position to achieve a better outcome through negotiation rather than accepting TasNetworks' regulated charges. However where local councils do not possess genuine countervailing power in negotiations, which would be the

⁷⁵ Consumer Challenge Panel sub Panel CCP4 - Submission to framework and approach preliminary positions paper - 13 May 2015, p.4.

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)(2).

case for a number of councils in Tasmania, the outcome may be frequent resort to regulatory intervention to arbitrate disputes. This would involve additional regulatory costs to TasNetworks, local councils and other parties. Our proposed approach is therefore to classify public lighting as an alternative control service, consistent with current arrangements.

New public lighting technology services

As discussed above, new public lighting technologies refers to services provided by public lighting infrastructure (e.g. equipment such as luminaires) that TasNetworks does not provide, or may not exist, at the time of our distribution determination. Such services are therefore not provided exclusively by TasNetworks and there is potential for other providers to enter the market.

Our proposed approach on new public lighting technologies is to continue the existing classification as a negotiated service. Submissions support this approach.

The Tasmanian Local Government Association submitted:

LGAT strongly supports that new technology remains classified as a negotiated service and that this classification is applied on a case by case basis referring to individual lighting types, not broad lighting categories. For example, now that a number of LED lights are in the process of being added to TasNetworks priced “suite of lights”, LGAT would not want to see the entire category of LED lose its ‘new technology’ status, given the rapid technological developments in this area. Councils strongly desire the ability examine and potentially trial new technology, ideally with the support of the Distribution and Network provider.⁸¹

We note that TasNetworks may propose to supply LED public lighting as an alternative control service in the next regulatory control period in which case the service would be subject to a price cap, as discussed above. Other 'new technology' public lighting services not offered by TasNetworks or subject to the alternative control classification at the time of our 2017-19 determination would be classified as negotiated services. That is, there is the potential for new public lighting technologies to be available during the next regulatory control period which may not exist or which TasNetworks has not proposed to supply as an alternative control service at the time of our distribution determination. Where TasNetworks offers such new technology public lighting services as a negotiated service in the 2017-19 regulatory control period, customers will be able to negotiate service provision and price under a framework established by the rules. Our role is to arbitrate disputes where TasNetworks and prospective customers cannot agree.

1.3.4 Connection services

Chapter 10 of the rules defines connection services.⁸² Put simply, a connection service refers to the services a distributor performs to:

⁸¹ Tasmanian Local Government Association - Submission to framework and approach preliminary positions paper - 1 July 2015, p.5.

⁸² NER, chapter 10 defines connection services as consisting of entry services and exit services. An entry service is a

- 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.⁸³

Our proposed approach is to maintain the current classification for TasNetworks' standard connection services and connections requiring augmentation as standard control services. 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.⁸⁴ 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. 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 for the first time 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 2017–19 regulatory control period.

When determining the classification of services we examine the way in which the services are defined.⁸⁵ We are seeking to achieve as much consistency as practical across

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.

⁸³ 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.

⁸⁴ AER, Connection charge guidelines for electricity retail customers, Under chapter 5A of the National Electricity Rules, June 2012.

⁸⁵ AER, Final Decision, Connection charge guidelines: under chapter 5A of the National Electricity Rules, For retail

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:

- 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:⁸⁶

- 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.
- If the cost of the connection cannot be easily attributed to an individual customer, then a standard control service classification might be appropriate.
- 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

⁸⁶ customers accessing the electricity distribution network, June 2012.
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.

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.⁸⁷

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.⁸⁸ These factors support our view that TasNetworks possesses market power in providing connection services. Because of these barriers to competition from other service providers, we propose to continue classifying connection services as direct control services.⁸⁹

In our F&A preliminary positions paper we proposed to retain the current classification of connection services in Tasmania as direct control, standard control services.

TasNetworks submitted:

The AER's final connection charge guideline contains a provision to undertake an incremental revenue calculation as a component of the capital contributions that should apply to all connecting customers. The 2012 [Aurora Energy] Connection Policy does not contemplate revenue offset for the provision of a basic connection service. A continued classification of these services as direct control, standard control, will mean that the full application of the AER's connection charge guideline should apply and that incremental revenue will apply to this capital contribution. This change will mean that the user-pays signal currently embedded for basic connection services will effectively be removed.

These basic connection services can be linked to an individual customer and it is appropriate to recover the costs of providing these services from the individual customer. TasNetworks therefore proposes that the provision of basic connection services, including associated connection alteration services, is classified as direct control, alternative control services. This will preserve the current user-pays, cost reflective charging mechanism that applies for customers receiving a basic connection service. It also reflects that the service is provided to a particular customer who pays directly for the service.

Prior to the implementation of the 2012 [Aurora Energy] Connection Policy, no connection pricing signals were provided to customers, as the costs associated with connection formed a component of the charges that are levied on all customers as part of the network tariffs. Customers and potential service providers had no benchmark cost for

⁸⁷ NEL, s. 2F(a).

⁸⁸ NEL, s. 2F(d).

⁸⁹ NEL, s. 2F(a)(d).

comparison and to date no party in Tasmania has provided basic connection services on a competitive basis. The removal of this user-pays pricing signal will make it more challenging to develop a market where other parties may provide these service.⁹⁰

And:

The Tasmanian Government recently released its Tasmanian Energy Strategy that notes opportunities to make the connection process more timely and transparent. The strategy states “TasNetworks is considering options to improve connection services, including making connection services contestable”. Moving to choice of service providers for basic connection services will be facilitated by the classification of these services as alternative control services.⁹¹

The Consumer Challenge Panel submitted:

In October 2014 there was a request from TasNetworks Distribution to transfer some connection services to alternative control services but this request was withdrawn by TasNetworks Distribution in March 2015. CCP4 sees that the cost-revenue test used to assess the capital contribution a new connection acts to prevent other consumers contributing for the new connection through the standard. Equally, CCP4 notes that the addition of a new connection should increase demand and consumption of electricity thereby spreading the cost of the shared network over a larger base, effectively reducing shared network costs for all consumers. CCP4 agrees with the AER that new connections should be retained as a standard control service.⁹²

Our proposed approach is to retain the current classification of connection services as standard control services. 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 as proposed by TasNetworks. However, the operation of Chapter 5A and our connection charge guidelines will implement a cost-revenue test for connection services, 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 from the connection over time. Provision for the requesting customer to make a capital contribution, where the application of the cost-revenue 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.

Under TasNetworks proposal to classify basic connection services as alternative control services, a new customer would have to pay the up-front costs of the basic connection service irrespective of whether this is offset by the incremental revenue to TasNetworks generated from the connection. The cost-revenue test applied to standard control services under our connection charge guidelines determines whether an additional upfront capital contribution is required in order to improve user pays signals and reduce the level of cross-

⁹⁰ TasNetworks - Submission to framework and approach preliminary positions paper - 15 May 2015, p.5.

⁹¹ TasNetworks - Submission to framework and approach preliminary positions paper - 15 May 2015, p.6.

⁹² Consumer Challenge Panel sub Panel CCP4 - Submission to framework and approach preliminary positions paper - 13 May 2015, p.5.

subsidies between customers. The 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 TasNetworks will receive from that customer.⁹³

We must act on the basis that there should be no departure from a previous classification unless another classification is clearly more appropriate.⁹⁴ We consider the current standard control classification supports the operation of Chapter 5A and our connection charge guidelines and provides a framework for consumers to understand where additional contributions may be required.

We consider that retaining the current classification of connection services as standard control services would have 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.

TasNetworks' submission raised the prospect that connection services may be contestable in Tasmania in the future, referring to the 2015 Tasmanian Energy Strategy. In regard to contestability for connection services, the Tasmanian Energy Strategy states:

The COAG Energy Council (CEC) is currently looking at building a 'national contestability framework for electricity and gas distribution network connections'. Contestability is available in New South Wales with other states exploring the option. This could help create greater competition for these services, including greater private sector activity in Tasmania.

Some contestability is already available for transmission assets in Tasmania, with further reforms being considered nationally to further increase contestability.⁹⁵

The Tasmanian Energy Strategy also identifies a:

Review [of] network customer connection processes and outcomes to identify opportunities for reform⁹⁶

as one of the Strategy's actions for 2016-17.

Should the Tasmanian Government implement contestability in the Tasmanian market for connection services in the future we will consider the implications for classification of these

⁹³ 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.

⁹⁴ NER, cl. 6.2.2(d).

⁹⁵ Tasmanian Department of State Growth, Restoring Tasmania's Energy Advantage, Tasmanian Energy Strategy, May 2015, p.19.

⁹⁶ Tasmanian Department of State Growth, Restoring Tasmania's Energy Advantage, Tasmanian Energy Strategy, May 2015, p.23.

services in the 2017-19 and subsequent regulatory periods. Currently, we consider connection services exhibit the monopoly characteristics of direct control, standard control services discussed above and that our classification of these services will not influence the potential for competition.

Our proposed approach is to retain the current standard control services classification for TasNetworks' standard connection services and connections requiring augmentation.

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'. Examples of these services are set out in appendix B.

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

Our proposed approach is to retain the current alternative control service classification for fee-based and 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.⁹⁷ 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.⁹⁸ These factors contribute to our 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.⁹⁹

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

⁹⁷ NEL, s. 2F(a).

⁹⁸ NEL, s. 2F(d).

⁹⁹ NEL, s. 2F(a)(d).

continue classifying ancillary network services as alternative control because they are attributable to individual customers.¹⁰⁰ 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 distributors, users or potential users.¹⁰¹ 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.¹⁰² 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 2017-19 regulatory control period.

1.4 AER's proposed approach to service classification

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

¹⁰⁰ NER, clause 6.2.2(c)(5).

¹⁰¹ NER, clause 6.2.2(c)(2).

¹⁰² NER, clause 6.2.2(c)(5).

2 Control mechanisms

This attachment sets out our decision, together with our reasons, on form of control mechanisms to apply to TasNetworks' direct control services for the 2017–19 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. 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 and Appendix B provides our proposed classification of Tasmanian distribution services. Broadly, we will classify a service as a direct control service if the distributor is a natural monopoly provider of the service. Typically, we split direct control services into standard and alternative control services based on the customer base for the service. For example, if the broad customer base benefits from a service, we will classify it as a standard control service. If a distributor only provides a service to specific customers, or if there is potential for competition to develop in the provision of that service, we will classify it as an alternative control service.

We can only approve the forms of control in a distributor's regulatory proposal if is identical to that set out in this F&A.¹⁰³ 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 this F&A, unless we consider that unforeseen circumstances justify departing from the formulae set out.¹⁰⁴

2.1 AER's decision

We have decided to apply the following forms of control in the 2017–19 regulatory control period:

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

2.2 AER's assessment approach

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

- the form of the control mechanisms¹⁰⁵
- the formulae to give effect to the control mechanisms

¹⁰³ NER, clause 6.12.3(c).

¹⁰⁴ NER, clause 6.12.3(c1).

¹⁰⁵ NER, clause 6.2.5(b).

- the basis of the control mechanism.¹⁰⁶

The rules set out the control mechanisms that may apply to both standard and alternative control services.¹⁰⁷

- 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 services¹⁰⁸

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.

- 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

¹⁰⁶ NER, clause 6.2.6(a).

¹⁰⁷ NER, clause 6.2.5(b).

¹⁰⁸ 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.

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 proposed approach, 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 have had 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 have had 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.¹⁰⁹

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

¹⁰⁹ 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 wants¹¹⁰
- 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.

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.

¹¹⁰ 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.

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.¹¹¹ 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 considered 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
- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)
- any other relevant factor.

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.¹¹² 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.¹¹³

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. 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

¹¹¹ Generally peak demand is referred to as the maximum load on a section of the network over a very short time period.

¹¹² NER, clause 6.2.6(b).

¹¹³ NER, clause 6.2.6(c).

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:

- 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.¹¹⁴ 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.¹¹⁵ In reviewing the form of control in NSW¹¹⁶ 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.

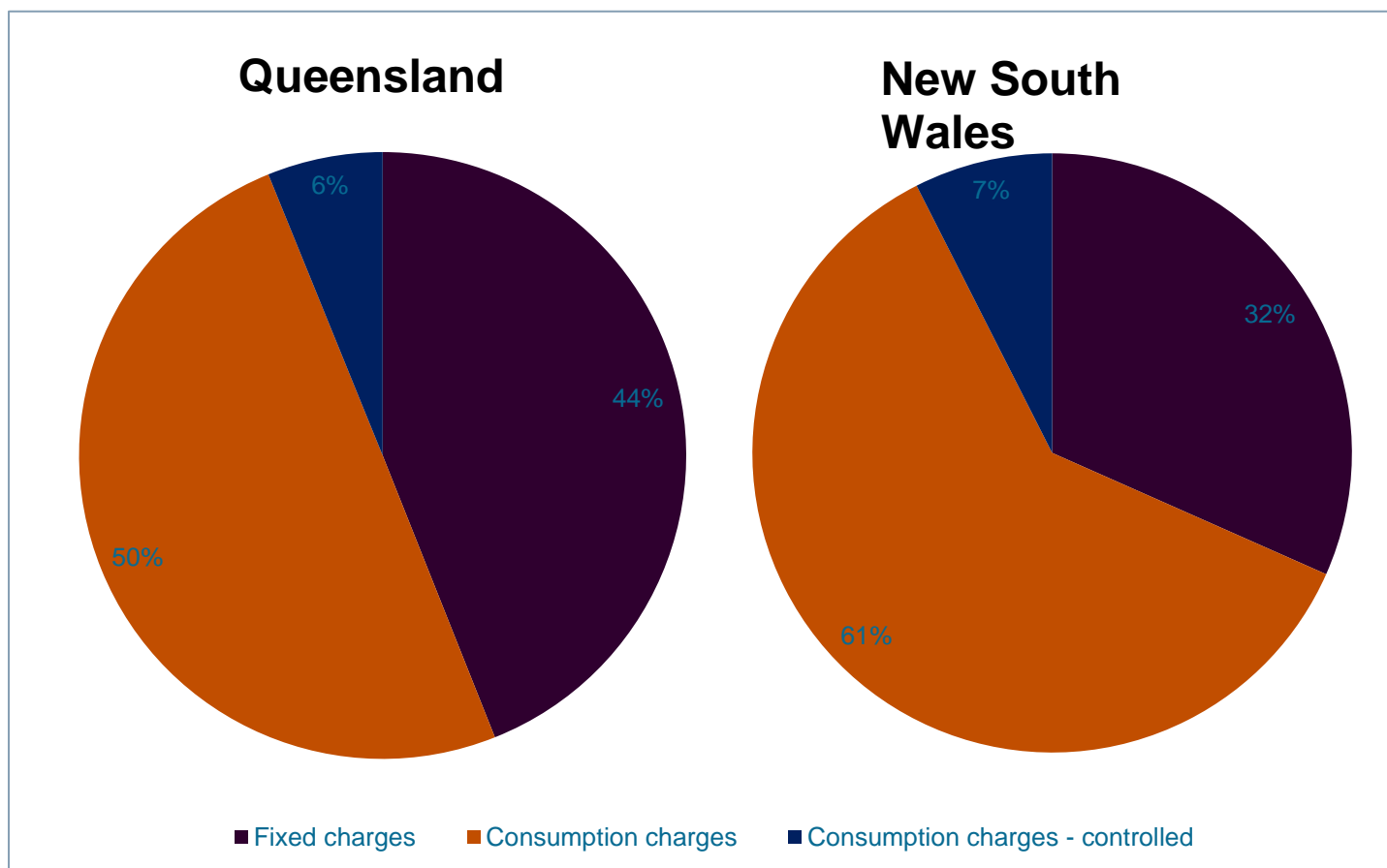
Figure 4 below compares the Queensland distributors under their current revenue cap and the WAPC the NSW distributors have operated under in recent years. From the figures below we can see that despite operating under a revenue cap, the Queensland distributors have a higher proportion of revenues raised 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.

¹¹⁴ Peak prices include peak energy, demand and capacity prices.

¹¹⁵ AER, Stage 1 NSW framework and approach Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019, March 2013, p. 45

¹¹⁶ 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 and South Australia and have determined a revenue cap in 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 in most circumstances a revenue cap is likely to allow the business to recover efficient costs over the regulatory period. 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 is likely to either over-recover or under-recover revenues. If energy use is increasing unexpectedly, the WAPC provides an opportunity for distributors to recover revenues systematically above forecast. But if energy use is less than forecast, revenues are unlikely to fully recover costs. In contrast, a revenue cap sets the maximum allowable revenue for each year of the regulatory control period. A distributor must then recover revenue less than or equal to this maximum.

2.3.6 Pricing flexibility

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.¹¹⁷

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,¹¹⁸ 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.¹¹⁹ 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.¹²⁰

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 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

¹¹⁷ These include cost pass throughs, jurisdictional scheme obligations, tribunal decisions and transmission prices passed on to the distributors from Transmission Network Service Providers.

¹¹⁸ AER, Final distribution determination, Aurora Energy Pty Ltd, 2012–13 to 2016–17, attachments, April 2012, pp. 2–24.

¹¹⁹ 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) is used in the calculation of the under or over recovery. This will reduce the likelihood of undesirable price shocks by smoothing the under and over recovery using more updated and accurate estimated and forecast data in the middle year.

¹²⁰ 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.

quantities. Similarly, they are able to 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.

TasNetworks has advised that it may have a large under-recovery of allowable revenue for standard control services at the end of the current regulatory control period and that an adjustment to recover the revenue in the first year of the next regulatory period (2017-18) could lead to a price shock.¹²¹ TasNetworks has not provided a forecast of the amount of any under-recovery of allowable revenue in the current period or its potential price impact in the next period. This information will be provided in TasNetworks' 2017-19 regulatory proposal. As noted above, we designed the unders and overs account for the 2012-17 regulatory control period to help smooth price adjustments year on year to reduce the likelihood of undesirable price shocks. We note that the form of control set out in this attachment provides flexibility to smooth price adjustments over the next regulatory control period. We will further consider the issue raised by TasNetworks after we receive its 2017-19 regulatory proposal.

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.¹²² We consider this provides an efficient incentive for a distributor to undertake demand side management within a regulatory control period.

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

¹²¹ TasNetworks - Submission to framework and approach preliminary positions paper - 15 May 2015, p.8.

¹²² 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.

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 for NSW.¹²³ Other regulators (Queensland Competition Authority and OTTER) have also noted the difficulties and complexities involved in developing and applying a hybrid revenue cap.¹²⁴

2.3.10 Formulae for control mechanism

We are required to set out our approach to the formulae that give effect to the control mechanisms for standard control services in the F&A.¹²⁵ We must include the formulae in our F&A in our distribution determination, unless we consider that unforeseen circumstances justify departing from the formulae as set out in the F&A.¹²⁶

Below are the formulae to apply to TasNetworks' standard control services which we consider gives effect to the revenue cap.

$$(1) \quad TAR_t \geq \sum_{i=1}^n \sum_{j=1}^m p_{ij}^t q_{ij}^{*t} \quad i=1,\dots,n \text{ and } j=1,\dots,m \text{ and } t=1,2$$

$$(2) \quad TAR_t = AAR_t + I_t + B_t + C_t \quad t = 1,2$$

where;

$$(3) \quad AAR_t = AR_t \times (1 + S_t) \quad t = 1$$

$$(4) \quad AAR_t = AAR_{t-1} \times (1 + CPI_t) \times (1 - X_t) \times (1 + S_t) \quad t = 2$$

Where:

TAR_t is the total 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.

¹²³ IPART, Form of Economic Regulation for NSW Electricity Network Charges: Discussion Paper 48, August 2001, p. 10.

¹²⁴ 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.

¹²⁵ NER, clause 6.8.1(b)(2)(ii).

¹²⁶ NER, clause 6.12.3(c1).

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.

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

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 and the Electrical Safety Inspection Service charge and the National Energy Market charge. To be decided in the determination.

C_t is the sum of cost pass through adjustments in year t. To be decided in the determination.

CPI_t is the percentage increase in the consumer price index. The method for calculating the annual change in the index is to be decided in the determination.

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 determination.

S_t is the s-factor for regulatory year t.¹²⁷ It will also incorporate any adjustments required due to the application of the STPIS in the 2012-17 regulatory control period consistent with the AER's STPIS.¹²⁸

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

We will apply caps on the prices of individual services classified as alternative control services in the next regulatory control period. 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).

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

¹²⁷ The meaning for year “t” under the price control formula is different to that in Appendix C of STPIS. Year “t+1” in Appendix C of STPIS is equivalent to year “t” in the price control formula of this decision.

¹²⁸ AER, Electricity distribution network service providers - service target performance incentive scheme, 1 November 2009.

Through the distribution determination process, we will confirm the basis of the control mechanism for alternative control services.¹²⁹ 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 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 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 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 position to apply caps on the prices of individual services is consistent with the current regulatory arrangements in Tasmania.

¹²⁹ 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.

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 approach to the formulae that give effect to the control mechanisms for alternative control services in the F&A.¹³⁰ We must include the formulae in our F&A in our distribution determination, unless we consider that unforeseen circumstances justify departing from the formulae as set out in the F&A.¹³¹

The price cap formulae set out below will apply to the following services classified as alternative control services in this F&A:

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

Below are the formulae to apply to TasNetworks' alternative control services which we consider gives effect to a cap on the prices of individual services:

$$\bar{p}_i^t \geq p_i^t \quad i=1,\dots,n \text{ and } t=1,\dots,2$$

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

Where:

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

¹³⁰ NER, clause 6.8.1(b)(2)(ii).

¹³¹ NER, clause 6.12.3(c1).

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

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

X_i^t is the X-factor for service i in year t .

3 Incentive schemes

This attachment sets out our proposed approach on the application of a range of incentive schemes to TasNetworks for the next regulatory control period. At a high level, our proposed approach 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 STPIS¹³² provides a financial incentive to distributors to maintain and improve service performance. The STPIS aims to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributor's incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (NEO).

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

- The service standards factor (s-factor) adjustment to the annual revenue allowance for standard control services rewards (or penalises) distributors for improved (or diminished) service compared to predetermined targets. Targets relate to service parameters pertaining to reliability and quality of supply, and customer service.
- A guaranteed service level (GSL) component composed of direct payments to customers¹³³ experiencing service below a predetermined level.¹³⁴

While the mechanics of how the STPIS operates 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

¹³² AER, Electricity distribution network service providers - service target performance incentive scheme, 1 November 2009.

¹³³ Except where a jurisdictional electricity GSL requirement applies.

¹³⁴ Service level is assessed (unless we determine otherwise) with respect to parameters pertaining to the frequency and duration of interruptions; and time taken for streetlight repair, new connections and publication of notices for planned interruptions.

- the 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.¹³⁵ 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, as set out in the STPIS.

Our national STPIS currently applies to TasNetworks which is subject to a 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 proposed approach

Our proposed approach 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 appropriate value of customer reliability (VCR) to the calculation of incentive rates.

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

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

¹³⁵ AER, Electricity distribution network service providers – service target performance incentive scheme, 1 November 2009, clause 2.2.

measures in the NEM.¹³⁶ 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.¹³⁷ 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.¹³⁸ 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
- 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.¹³⁹

¹³⁶ AEMC, Final Report, Review of distribution reliability measures, 5 September 2014.

¹³⁷ AEMO, Value of customer reliability review - Final report, September 2014.

¹³⁸ NER, clause 6.6.2(b).

¹³⁹ AER, Final decision: Electricity distribution network service providers Service target performance incentive scheme, 1 November 2009.

3.1.3 Reasons for AER's proposed approach

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.¹⁴⁰ Our proposed approach to applying the STPIS in Tasmania is to not create duplication or compromise TasNetworks' ability to comply with the jurisdictional requirements. Our proposed approach is therefore to not apply the GSL component of our national STPIS while the GSL arrangements in the Tasmanian code remain in place. We will amend this position if the Tasmanian Government advises that these arrangements will cease to apply.

Benefits to consumers

We are mindful of the potential impact of the STPIS on consumers. Under the 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.¹⁴¹

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 the VCR to set incentive rates for each reliability of supply parameter.

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.¹⁴²

In September 2014 AEMO completed analysis of the VCR across the NEM.¹⁴³ 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 proposed 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 we developed the STPIS, we considered the VCR figures should be

¹⁴⁰ OTTER, Guideline - Guaranteed Service Level Scheme, December 2007.

¹⁴¹ NER, clause 6.6.2(b)(3)(vi).

¹⁴² 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.

¹⁴³ AEMO, Value of customer reliability review - Final report, September 2014.

based on the most recent documented and robust work on reliability incentive rates.¹⁴⁴ 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.

In response to our preliminary position to maintain revenue at risk for TasNetworks under the STPIS within the range ± 5 per cent,¹⁴⁵ TasNetworks stated:

A range of customer consultation activities conducted by TasNetworks indicates that customers are generally not seeking improvements in the current levels of reliability and are happy with the service/price trade-off they are receiving. They also support measures to reduce annual price volatility.

The current STPIS operation, with 5% of revenue at risk, contributes to price volatility.¹⁴⁶

And:

We consider that a ± 2.5 per cent cap retains the appropriate service incentive while reducing pricing volatility for customers.¹⁴⁷

Meander Valley Council also commented on our preliminary position to maintain revenue at risk within the range ± 5 per cent, stating:

In the interests of providing more predictable pricing for customers, therefore, Meander Valley Council supports TasNetworks' proposal to reduce the revenue at risk to TasNetworks to ± 2.5 per cent of its annual smoothed revenue.¹⁴⁸

The Consumer Challenge Panel submitted:

CCP4 notes that TasNetworks Distribution prefers the revenue at risk from the STPIS be limited to $\pm 2\%$ whereas the national STPIS has $\pm 5\%$ of revenue at risk. As noted above, there is tension between the different incentive schemes and the design of each reflects that this tension is balanced. If the revenue at risk is reduced for the STPIS there would need to be concurrent changes in the other schemes (especially for opex and capex) to reflect this balance. With this in mind, CCP\$ (sic) supports the AER preliminary position that the STPIS should retain $\pm 5\%$ of revenue at risk unless there are changes proposed for the other schemes.¹⁴⁹

Our proposed approach 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. TasNetworks may propose an alternative VCR estimate and revenue at risk,

¹⁴⁴ AER, Electricity distribution network service providers Service target performance incentive scheme, Final decision, June 2008, p 17.

¹⁴⁵ AER, Preliminary positions on replacement framework and approach (for consultation) for TasNetworks Distribution for the Regulatory control period commencing 1 July 2017, April 2015.

¹⁴⁶ TasNetworks - Submission to framework and approach preliminary positions paper - 15 May 2015, p.9.

¹⁴⁷ TasNetworks - Submission to framework and approach preliminary positions paper - 15 May 2015, p.10.

¹⁴⁸ Meander Valley Council - Submission to framework and approach preliminary positions paper - 19 May 2015, p.3.

¹⁴⁹ Consumer Challenge Panel sub Panel CCP4 - Submission to framework and approach preliminary positions paper - 13 May 2015, pp.6-7.

supported by details of the calculation methodology, research and customer consultation, in its regulatory proposal. To date we have received only anecdotal evidence supporting the view that TasNetworks' customers are not seeking improvements in the current levels of reliability and prefer to maintain the current service/price trade-off. As previously stated,¹⁵⁰ we consider it less likely that customers would be satisfied with a deterioration in reliability and note that the potential for deterioration in service performance will increase if revenue at risk is reduced under the STPIS.

Regarding the price volatility issues raised by TasNetworks and Meander Valley Council, our national STPIS includes a banking mechanism, allowing TasNetworks to propose delaying a portion of the revenue increment or decrement arising from the STPIS to limit price volatility for customers.¹⁵¹ TasNetworks is required to provide in writing its reasons and justification for believing that the delay will result in reduced price variations to customers. To date, applying the STPIS with a ± 5 per cent revenue at risk has not resulted in price volatility for distribution services in Tasmania. TasNetworks' use of the banking mechanism has resulted in very minor revenue and price impacts between 2014-15 and 2015-16.¹⁵² The data available shows that the banking component of the STPIS is working as designed.

We note also that the revised AEMO VCR values referred to above are lower than the values currently in the STPIS. 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.

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 Consumer Challenge Panel submitted:

CCP4 notes that the settings for reliability (the duration index - SAIDI and the frequency index - SAIFI) will be set at the average of the past five years of network performance.

CCP4 considers that this is not appropriate as it does not reflect the benefits from opex and capex that occurs during the regulatory period. CCP4 considers that targets should

¹⁵⁰ AER, Preliminary positions on replacement framework and approach (for consultation) for TasNetworks Distribution for the Regulatory control period commencing 1 July 2017, April 2015.

¹⁵¹ AER, Electricity distribution network service providers – service target performance incentive scheme, 1 November 2009, clauses 2.5(d) and (e).

¹⁵² For service performance outcomes in 2012-13 and 2013-14 given the two year lag between service performance outcomes and rewards / penalties applied under the STPIS.

be based on a rolling average of the previous five yearly performance rather than static targets set at the commencement of each regulatory period. This is consistent with the approach to identifying (and rewarding/penalising) the benefits from the opex incentive scheme.¹⁵³

In addition to its underlying level of performance, TasNetworks' level of supply reliability each year is influenced by variable factors such as weather patterns. The use of a 5-year average performance target removes the effect of the majority of such annual variability factors. A fixed target also provides a clear objective for TasNetworks to implement and monitor its asset management policies; and for us to monitor the performance outcome. We consider that supply performance should be measured over a suitable period and the use of a moving target would not improve the effectiveness of the STPIS. Consequently we do not consider a different approach should apply in this instance.

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.

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.¹⁵⁴ 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.¹⁵⁵

In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.¹⁵⁶

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

¹⁵³ Consumer Challenge Panel sub Panel CCP4 - Submission to framework and approach preliminary positions paper - 13 May 2015, p.7.

¹⁵⁴ NER, clause 6.6.2(b)(3)(iv).

¹⁵⁵ NER, clause 6.6.2(b)(3)(v).

¹⁵⁶ Included in the distributor's approved forecast capex for the next period.

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.

We consider the current incentive framework of the STPIS is adequate to encourage distributors to select appropriate network or non-network solutions to manage their networks.

Exclusion of outages caused by non-network solutions from the calculation of actual performance under STPIS will transfer the financial risk of non-network solution operators to customers. Non-network solution operators and the distributor are the parties best placed to manage the risk rather than the customers.

Our considerations are consistent with the findings of the AEMC's December 2009 Market Review of Demand Side Participation in the NEM, Stage 2 Final Report, in which the AEMC noted that:

- the service that is desired by customers is continuity of supply, with quality of supply (e.g. voltage) within acceptable limits
- the design of the [service incentive] schemes do not present barriers to the efficient inclusion of [Demand-Side Participation] DSP. This means that DSP options will be given consideration if they can improve reliability at relatively low cost rather than being summarily dismissed if they are considered less reliable. Rather, the possible penalty from a lower level of reliability will be considered and valued compared to the cost of the option and possible benefit. Therefore, if the cost of the DSP option is sufficiently low, and the risk of it impacting on the quality of supply can also be managed at a low cost, the network owner will prefer the DSP option.¹⁵⁷

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.

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

3.2.1 AER's proposed approach

We propose applying our new EBSS (version 2)¹⁵⁸ to TasNetworks for the 2017–19 regulatory control period.

¹⁵⁷ AEMC, Market Review of Demand Side Participation in the NEM, Stage 2 Final Report, December 2009, p.33.

¹⁵⁸ AER, Efficiency benefit sharing scheme, 29 November 2013.

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.¹⁵⁹ We must also have regard to the following factors in developing and implementing the EBSS:¹⁶⁰

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

3.2.3 Reasons for AER's proposed approach

The current EBSS applies to TasNetworks in the 2012–17 regulatory control period.¹⁶¹ 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.¹⁶² 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.¹⁶³

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

In developing the new EBSS we had regard to the requirements under the rules, as set out in the scheme and accompanying explanatory statement.¹⁶⁴ This reasoning extends to the factors we must have regard to in implementing the scheme.

¹⁵⁹ NER, clause 6.5.8(a).

¹⁶⁰ NER, clause 6.5.8(c).

¹⁶¹ AER, Electricity distribution network service providers, efficiency benefit sharing scheme, 26 June 2008.

¹⁶² 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.

¹⁶³ AER, Efficiency benefit sharing scheme for electricity network service providers, 29 November 2013.

¹⁶⁴ 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.

The EBSS must provide for a fair sharing of efficiency gains and losses.¹⁶⁵ 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.¹⁶⁶ 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.¹⁶⁷

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.¹⁶⁸ For instance the combined effect of our forecasting approach and the EBSS applying a five year carryover period 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.¹⁶⁹

¹⁶⁵ NER, clause 6.5.8(a).

¹⁶⁶ NER, clauses 6.5.8(c)(3) and 6.5.8(a).

¹⁶⁷ NER, clause 6.5.8(c)(2).

¹⁶⁸ NER, clause 6.5.8(c)(1).

¹⁶⁹ See also: AER, Explanatory statement, Efficiency benefit sharing scheme for electricity network service providers, 29 November 2013.

Example 1 How the EBSS operates

Year	Regulatory period 1					Regulatory period 2					Future
	1	2	3	4	5	6	7	8	9	10	
Forecast (Ft)	10	10	10	10	10	95	95	95	95	95	95 p.a.
Actual (At)	10	10	10	95	95	95	95	95	95	95	95 p.a.
Underspend (Ft – At = Ut)	0	0	0	5	5	0	0	0	0	0	0 p.a.
Incremental efficiency gain (It = Ut – Ut–1)	0	0	0	5	0	0*	0	0	0	0	0 p.a.
Carryover (I1)		0	0	0	0	0					
Carryover (I2)			0	0	0	0	0				
Carryover (I3)				0	0	0	0	0			
Carryover (I4)					5	5	5	5	5		
Carryover (I5)						0	0	0	0	0	
Carryover amount (Ct)						5	5	5	5	0	0 p.a.
Benefits to NSP (Ft – At +Ct)	0	0	0	5	5	5	5	5	5	0	0 p.a.
Benefits to consumers (F1 – (Ft +Ct))	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, I6 = U6 – (U5 – U4). ** 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.¹⁷⁰ 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:¹⁷¹

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.¹⁷² 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.¹⁷³

3.2.4 Two year regulatory control period

As discussed above, applying a five year carryover period under the EBSS results in a distributor retaining approximately 30 per cent of efficiency gains and losses. The remaining 70 per cent is retained by customers. Shorter carryover periods lessen incentives for efficient expenditure under the EBSS as the proportion of efficiency gains and losses allocated to a distributor is reduced.

The EBSS (version 2) we propose to apply to the 2017-19 regulatory control period allows flexibility in the length of the carryover period where the length of the regulatory control period is not five years. For example, although TasNetworks' next regulatory control period is two years, a longer carryover period for efficiency gains and losses may be applied under the EBSS. As noted in the Explanatory Statement¹⁷⁴ for the EBSS, we determine the scheme's carryover period length in the revenue determination for a distributor.

¹⁷⁰ NER, clause 6.5.8(c)(4).

¹⁷¹ NER, clause 6.5.8(c)(5).

¹⁷² 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.

¹⁷³ 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.

¹⁷⁴ AER, Better Regulation, Explanatory Statement, Efficiency Benefit Sharing Scheme for Electricity Network Service

3.3 Capital expenditure sharing scheme

The CESS provides financial rewards for distributors whose capex becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices. This section sets out our proposed approach and reasons for how we intend to apply 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.¹⁷⁵ 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.

3.3.1 AER's proposed approach

Our proposed approach is to apply the CESS, as set out in our capex incentives guideline,¹⁷⁶ 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:¹⁷⁷

- make that decision in a manner that contributes to the capex incentive objective¹⁷⁸

Providers, November 2013, p.23.

¹⁷⁵ 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.

¹⁷⁶ AER, Capital expenditure incentive guideline for electricity network service providers, pp. 5–9.

¹⁷⁷ NER, clause 6.5.8A(e).

¹⁷⁸ NER, clause 6.4A(a); the capex criteria are set out in clause 6.5.7(c) of the NER.

- consider the CESS principles,¹⁷⁹ capex objectives,¹⁸⁰ other incentive schemes, and where relevant the opex objectives, as they apply to the particular distributor, and the circumstances of the distributor.

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

3.3.3 Reasons for AER's proposed approach

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.¹⁸¹ The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast depreciation to roll-forward the RAB.¹⁸² 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.¹⁸³ 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 loss will be penalised through the CESS. In this way, a distributor will be more likely to incur only efficient capex when subject to a CESS, so any capex included in the RAB is more

¹⁷⁹ NER, clause 6.5.8A(c).

¹⁸⁰ NER, clause 6.5.7(a).

¹⁸¹ AER, Capital expenditure incentive guideline for electricity network service providers, pp. 5–9.

¹⁸² AER, Capital expenditure incentive guideline for electricity network service providers, pp. 10–12.

¹⁸³ 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.

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.

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 proposed approach and reasons for applying a demand management incentive scheme (DMIS) to TasNetworks in the next regulatory control period.¹⁸⁴

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.¹⁸⁵ 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.¹⁸⁶ 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 control period.

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 DMIA¹⁸⁷ in the previous year, which we then assess against specific criteria.

The DMIS previously applied in other jurisdictions also compensates a distributor for any foregone revenue demonstrated to have resulted from demand management initiatives

¹⁸⁴ 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.

¹⁸⁵ 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.

¹⁸⁶ NER, clause 6.6.3(a).

¹⁸⁷ The DMIA excludes the costs of demand management initiatives approved in our determination for the 2012–17 period.

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 it is proposed that a revenue cap will apply in the next regulatory control period, compensation for foregone revenue will not be relevant to TasNetworks in this period.

3.4.1 AER's proposed approach

Our proposed approach is to continue applying the DMIS to TasNetworks in the next regulatory control period.

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.¹⁸⁸ The requests are in response to recommendations made by the AEMC in its Power of Choice review.¹⁸⁹ On 28 May 2015 the AEMC released its draft determination in response to the rule change requests. The draft determination includes a requirement for the AER to develop and publish a new DMIS in accordance with the distribution consultation procedures by 1 December 2016. Subject to the AEMC's final determination we intend to apply a new DMIS to TasNetworks for the 2019-24 regulatory control period. Our proposed approach is to continue to apply the current DMIS to TasNetworks for the 2017-19 regulatory control period.

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.¹⁹⁰ 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

¹⁸⁸ AEMC, Consultation paper, National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015, 19 February 2015. <http://www.aemc.gov.au/Rule-Changes/Demand-Management-Embedded-Generation-Connection-I#>.

¹⁸⁹ AEMC, Final report, Power of choice review – giving consumers' choice in the way they use electricity, 30 November 2012.

¹⁹⁰ NER, clause 6.6.3(b).

- the possible interactions between a DMIS and the other incentive schemes.

3.4.3 Reasons for AER's proposed approach

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

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.¹⁹¹

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 studies¹⁹² 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.

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.¹⁹³ We consider that a revenue cap form of control does not provide a disincentive for TasNetworks to reduce the quantity of electricity supplied as approved regulated revenues are not dependent on the quantity of electricity sold. That is, under a

¹⁹¹ NER, clause 6.6.3(b)(1).

¹⁹² For example, Oakley Greenwood, Valuing reliability in the national electricity market, final report, March 2011. This report was prepared for AEMO.

¹⁹³ NER, clause 6.6.3(b)(2).

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.¹⁹⁴ 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.¹⁹⁵ 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.¹⁹⁶ We note that the NER require distributors to develop efficient tariff structures consistent with the pricing principles for direct control services set out in the rules.¹⁹⁷

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.¹⁹⁸ 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.¹⁹⁹ 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.

¹⁹⁴ NER, clause 6.6.3(b)(6).

¹⁹⁵ NER, clause 6.6.3(b)(3).

¹⁹⁶ Aurora Energy, Pricing Proposal, 1 July 2014 - 30 June 2015, April 2014.

¹⁹⁷ NER, clause 6.18.1A. NER, clause 6.18.5.

¹⁹⁸ NER, clause 6.6.3(b)(4).

¹⁹⁹ 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 guideline²⁰⁰ including the information requirements to TasNetworks for the 2017–19 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.²⁰¹ 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.²⁰² In the F&A we must advise whether we will deviate from the guideline.²⁰³ 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 and any other appropriate tools for assessing expenditure forecasts. The tool kit set out in the guideline consists of:

- models for assessing proposed replacement and augmentation capex
- benchmarking (including broad economic techniques and more specific analysis of expenditure categories)
- methodology, governance and policy reviews
- predictive modelling and trend analysis
- cost benefit analysis and detailed project reviews.²⁰⁴

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

²⁰⁰ We published this guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864.

²⁰¹ NER, clauses 6.4.5, 6A.5.6, 11.53.4 and 11.54.4.

²⁰² NER, clauses 6.8.1A(b)(1) and 11.60.3(c).

²⁰³ NER, clause 6.8.1(b)(2)(viii).

²⁰⁴ AER, Explanatory statement: Expenditure assessment guideline for electricity transmission and distribution, 29 November 2013.

Information Notice that we will issue to TasNetworks for the next regulatory control period. This will occur in 2015 after we have published our F&A.

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 proposed approach to calculating depreciation when the RAB is rolled forward to the commencement of the 2019–24 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.²⁰⁵ 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.

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 proposed approach

Our proposed approach is to use the forecast depreciation approach to establish the RAB at the commencement of the 2019–24 regulatory control period for TasNetworks. We consider

²⁰⁵ AER, Capital expenditure incentive guideline for electricity network service providers, pp. 10–12.

this approach will provide sufficient incentives for TasNetworks to achieve capex efficiency gains over the 2017–19 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.²⁰⁶

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.²⁰⁷ Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective. We must have regard to:²⁰⁸

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

5.3 Reasons for AER's proposed approach

Consistent with our capex incentives guideline, we propose to use the forecast depreciation approach to establish the RAB at the commencement of the 2019–24 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.²⁰⁹

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.

²⁰⁶ NER, clause S6.2.2B.

²⁰⁷ NER, clause 6.4A(b)(3).

²⁰⁸ NER, clause S6.2.2B.

²⁰⁹ AER, Capital expenditure incentive guideline for electricity network service providers, pp. 10–12.

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.²¹⁰

The opening RAB for the 2017–19 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 2019–24 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.²¹¹ Therefore, we do not see the need to apply actual depreciation at this time.

²¹⁰ 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.

²¹¹ 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

This attachment sets out our position on dual function assets and our proposed approach regarding TasNetworks' two year 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 decision is that we are not required to, and will not, make any determination under the rules regarding dual-function assets.²¹²

6.2 Regulatory control period

In October 2014 TasNetworks 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. TasNetworks proposed 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 required by the rules.²¹³ The AEMC assessed this rule change request and published a final rule determination on 9 April 2015 accepting TasNetworks' proposal.

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

6.2.1 Incentive schemes

As discussed in attachment 3, our incentive scheme for opex (EBSS) is designed to operate over a five-year period with the length of the carryover period impacting on the proportion of efficiency gains and losses that is shared between a distributor and its customers.

Applying a five year carryover period under the EBSS results in a distributor retaining approximately 30 per cent of efficiency gains and losses. The remaining 70 per cent is retained by customers. Shorter carryover periods lessen incentives for efficient expenditure under the EBSS as the proportion of efficiency gains and losses allocated to a distributor is reduced.

²¹² NER, clauses 6.8.1(b)(1)(ii) and 6.25(b).

²¹³ NER, clause 6.3.2(b).

The EBSS (version 2) we propose to apply to the 2017-19 regulatory control period allows flexibility in the length of the carryover period where the length of the regulatory control period is not five years. For example, although TasNetworks' next regulatory control period is two years, a longer carryover period for efficiency gains and losses may be applied under the EBSS. As noted in the Explanatory Statement²¹⁴ for the EBSS, we determine the scheme's carryover period length in the revenue determination for a distributor.

Incentives for efficient opex under the EBSS generally correspond to incentives for efficient capex under our scheme for capital expenditure efficiency (CESS). Under the CESS a distributor retains 30 per cent of efficiency gains and losses with the remaining 70 per cent retained by customers. As discussed in attachment 3, where opex incentives are relatively balanced with capex incentives, a distributor does not have an incentive to favour opex over capex, or vice-versa, due to the operation of the EBSS and CESS.

Regarding the EBSS applied to TasNetworks' current regulatory control period, TasNetworks submitted:

The finalisation of the current EBSS assumes that efficiency outcomes will be applied to the full five years of the next regulatory control period. As the 2017 period will only be two years in duration, we propose that the efficiency outcomes from (sic) the EBSS are applied to the two years of the 2017 regulatory control period and the first three years of the regulatory control period beginning on 1 July 2019 as if the two regulatory control periods were a single period.²¹⁵

We note that the EBSS applied to TasNetworks' 2012-17 regulatory control period adopted a carryover period of five years to calculate carryover amounts. We will consider whether these carryover amounts can be incorporated in TasNetworks' maximum allowable revenue for 2017-19 and the subsequent regulatory control period in our distribution determination.

6.2.2 Framework and approach 2019–24

A two year regulatory control period commencing on 1 July 2017 and ending on 30 June 2019 results in the F&A consultation process for the 2019-24 regulatory control period commencing before our final revenue determination in April 2017 for the 2017-19 regulatory control period. Therefore, consideration of whether it is necessary or desirable to replace or amend this F&A would commence prior to implementation of the 2017-19 determination applying this F&A. While we do not anticipate that it will be necessary or desirable to replace or amend this F&A for the 2019-24 regulatory control period, we will consult publicly on this in November 2016 as required under the Rules.²¹⁶

²¹⁴ AER, Better Regulation, Explanatory Statement, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November 2013, p.23.

²¹⁵ TasNetworks - Submission to framework and approach preliminary positions paper - 15 May 2015, p.9.

²¹⁶ NER, cl. 6.8.1(a)(2).

Appendix A: Rule requirements for classification

We must have regard to four factors when classifying distribution services.²¹⁷

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.²¹⁸
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)²¹⁹
3. the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)²²⁰
4. any other relevant factor.²²¹

The rules specify additional requirements for services we have regulated before.²²² They are:

²¹⁷ NER, clause 6.2.1(c).

²¹⁸ NEL, s. 2F.

²¹⁹ NER, clause 6.2.1(c)(2).

²²⁰ NER, clause 6.2.1(c)(3).

²²¹ NER, clause 6.2.1(c).

²²² NER, clause 6.2.1(d).

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

We must have regard to six factors when classifying direct control services as either standard control or alternative control services.²²³

- the potential for development of competition in the relevant market and how the classification might influence that potential
- the possible effects of the classification on administrative costs of us, the distributor and users or potential users
- the regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made
- the desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction)
- the extent that costs of providing the relevant service are directly attributable to the customer to whom the service is provided, and
- any other relevant factor.²²⁴

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).

²²⁴ NER, clause 6.2.2(c).

Appendix B – Classification of Tasmanian electricity distribution services

Service group	AER's proposed classification 2017-19	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 works	Standard control	Standard control
Emergency recoverable works	Unclassified	Standard control
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

Service group	AER's proposed classification 2017-19	Current classification 2012-17
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
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 2019
NUOS	network use of system

Shortened Form	Extended Form
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

Appendix D - Submitters to preliminary positions paper

- Consumer Challenge Panel sub-panel CCP4
- Local Government Association of Tasmania
- Meander Valley Council
- Steel Wave Power
- TasNetworks Distribution
- Vector Limited