



**Final Framework and approach for Energex
and Ergon Energy**

**Regulatory control period commencing 1 July
2015**

April 2014

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Shortened form

Shortened form	Extended Form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
COAG Energy Council	Council of Australian Governments Energy Council (formerly Standing Council on Energy and Resources or SCER)
CPI	consumer price index
CPI-X	consumer price index minus X
current regulatory control period	1 July 2010 to 30 June 2015
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
F&A	Framework and approach
kWh	kilowatt hours
NECF	National Energy Customer Framework
NEM	National Electricity Market
NEO	National Electricity Objective
NER or the rules	National Electricity Rules

Shortened form	Extended Form
next regulatory control period	1 July 2015 to 30 June 2020
opex	operating expenditure
Qld	Queensland
RAB	regulatory asset base
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
STPIS	service target performance incentive scheme
WAPC	weighted average price cap

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 relevant incentive schemes. It also assists network service providers prepare regulatory proposals.

Energex and Ergon Energy (Qld distributors) are licensed, regulated operators of Queensland (Qld) monopoly electricity distribution networks. The networks comprise the poles, wires and transformers used for transporting electricity across urban and rural population centres to homes and businesses. These distribution network service providers (distributors) design, construct, operate and maintain distribution networks for Qld electricity consumers.

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

In September 2013, we made a decision to review the current Qld F&A for the next regulatory control period.² This decision arose following consultation with stakeholders.³ Our main reason for this decision was because of significant changes to the rules, making much of the current F&A irrelevant.

The current five year Qld distribution regulatory control period concludes on 30 June 2015. This paper sets out our decisions for the next regulatory control period from 1 July 2015 to 30 June 2020 on:

- control mechanisms (how we determine prices for regulated services)
- dual function assets.

It also sets out our proposed approach for the next regulatory control period on:

- distribution service classification (which services are to be regulated)
- the formulae that give effect to the control mechanisms
- service target performance incentive scheme
- efficiency benefit sharing scheme
- capital expenditure sharing scheme
- demand management incentive scheme

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

² AER, *Replacement of F&A for Queensland and South Australian electricity distribution businesses, 2015–2020*, September 2013.

³ NER, clauses 6.8.1(c)(1)–(3).

- small-scale 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 18 December 2013, seeking submissions from interested parties. Submissions closed on 19 February 2014, with 13 responses received. We also consulted our Consumer Challenge Panel (CCP).⁴ Submissions and CCP views have been considered in reaching our decisions and proposed approaches set out in this F&A. A summary of submissions and our response is also included at appendix A.

We will use the F&A process to commence discussions with the Qld distributors about the treatment of confidential information as set out in our confidentiality guideline.⁵ We encourage the Qld distributors to also consult consumers, as part of their consumer engagement, to gain a better understanding of the type of information consumers are interested in accessing.⁶

Table 1 summarises the Qld distribution determination process.

Table 1: Qld distribution determination process

Step	Date
AER published preliminary positions F&A for Qld distributors	18 December 2013
AER publishes final F&A for Qld distributors	30 April 2014
Qld distributors submit regulatory proposals to AER	31 October 2014
Submissions on regulatory proposal close	30 January 2015**
AER to publish preliminary distribution determination (prices set here take effect from 1 July 2014)	30 April 2015*
AER hold public forum on preliminary distribution determination	May 2015**
Qld distributors to submit revised regulatory proposal to AER	12 June 2015**
Submissions on revised regulatory proposal and preliminary determination close	July 2015**
AER to publish distribution determination for regulatory control period	31 October 2015

* The rules do not provide specific timeframes in relation to publishing draft decisions. Accordingly, this date is indicative only.

** The dates provided for submissions and the public forum are based on the AER receiving compliant proposals. These dates may alter if we receive non-compliant proposals.

Source: NER, chapter 6, Part E.

⁴ When we refer to the Consumer Challenge Panel or CCP, we mean the CCP sub-panel 2 for the Qld reset. Sub-panel members are Ms Bev Hughson, Ms Fiona McLeod, Mr Bruce Mountain, Mr Bob Lim and Mr Hugh Grant. Further information on the CCP can be found at www.aer.gov.au/node/19305.

⁵ AER, *Confidentiality guideline*, 19 November 2013.

⁶ 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 the Qld distributors 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
- treatment of dual function assets
- the application of a range of incentive schemes that encourage things like service quality, improvements in network reliability or efficient capital and operating expenditure
- the application of a range of expenditure forecasting expenditure tools used to test the Qld distributors' regulatory proposals
- how we will calculate depreciation of the distributors' 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, become involved only to arbitrate disputes, or do not regulate at all. The classification that we apply to a distribution service also determines whether the Qld distributors recover 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.	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 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 ⁷ or services that are contestable.	We have no role in regulating these services.

Source: AER

The classification of most distribution services will not change for the 2015–20 regulatory control period. The majority of services provided by distributors relate to building and maintaining the network and these will remain standard control services. Similarly, we propose public lighting remain an alternative control service. We propose changing the classification of some metering services and a number of ancillary network services that distributors provide to individual customers. Our proposed approach is to reclassify type 5 and 6 metering services from standard control to alternative control. This will facilitate more choice for customers. We also propose classifying ancillary network services as alternative control services to create a greater focus on 'user pays' for these services.

Direct control services

The rules set out factors we must have regard to when determining levels of economic regulation for the range of electricity distribution services. Following consideration of those factors, we may determine that a prescriptive approach is required. We will classify such services as direct control services. That is, we will directly set prices distributors may charge, or set revenues distributors may recover from customers through their charges.⁸

Most distribution services fall within the network services group, which includes poles, wires, and other core infrastructure of a distribution business.⁹ These are central to a distributor's business and its 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, supply competition. We therefore also propose to classify as direct control: some metering,

⁷ A distribution service is a service provided by means of, or in connection with, a distribution system. NER, Chapter 10.

⁸ 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).

⁹ Appendix B sets out the Qld distributors' distribution services in more detail.

connections, public lighting and ancillary network services. We must further determine whether we will classify a direct control service as a standard control or alternative control service.

Standard control services

We classify as standard control those distribution services that are central to electricity supply and therefore relied on by most (if not all) customers. Standard control services reflect the integrated nature of an electricity distribution system. The costs of providing standard control services are averaged across all customers of a distribution network and recovered through standard network charges. These standard control services form the core distribution component of an electricity bill.

We propose to classify network services, small customer connections and type 7 metering, as standard control services. These services encompass construction, maintenance and repair of the network, as well as connecting new small 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. For alternative control services we set 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. Therefore our proposed approach is to classify ancillary network services as alternative control.

Our proposed approach is to classify type 5 and 6 metering services as alternative control because provision of these services is likely to become open to more competition in future. The increasing range of metering services customers may wish to use (for example, smart meters) also suggests we should unbundle these services from standard control.

We propose to retain the current alternative control classification for large customer connections, as the market for provision of this service in Queensland is still developing. We also propose to retain the current alternative control classification for public lighting, because a defined group of customers purchase these services, for example, local councils.

Negotiated distribution services

Negotiated distribution services are those we consider require a less prescriptive regulatory approach because all relevant parties have sufficient market power to negotiate 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 not to classify any services provided by the Qld distributors as negotiated distribution services.

Unclassified (unregulated)

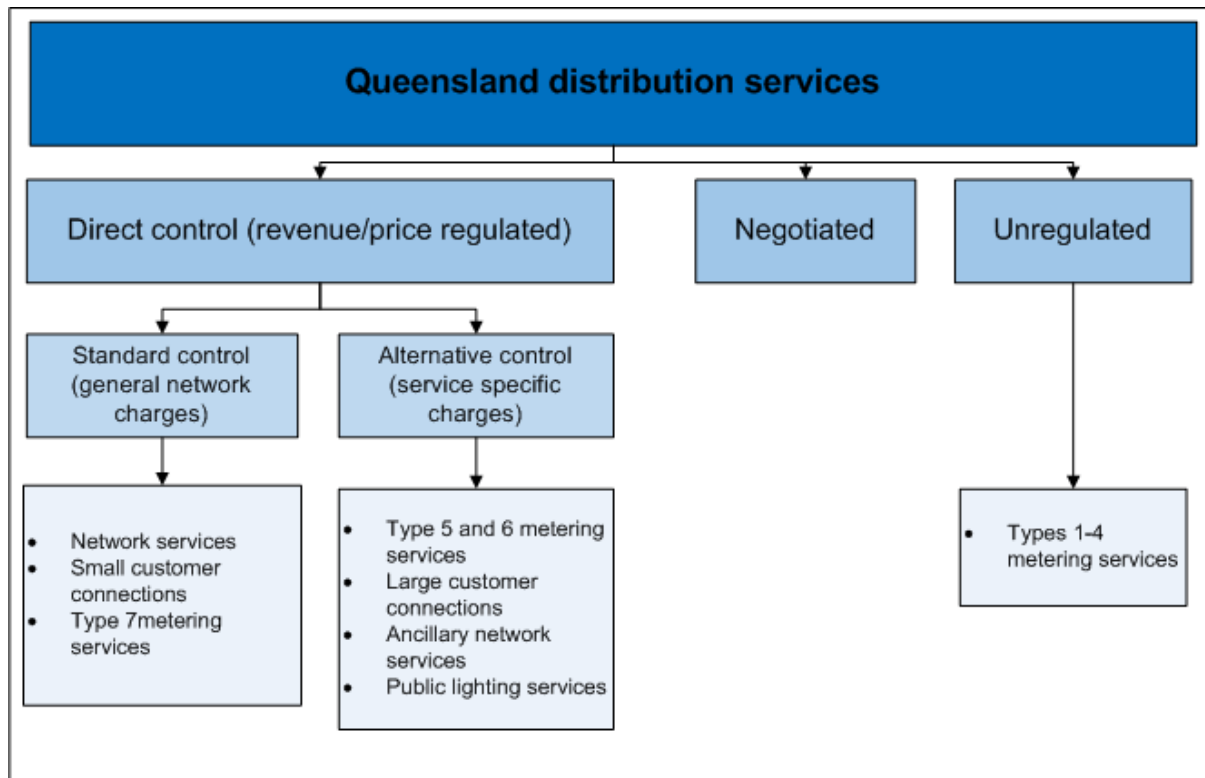
In the case of some distribution services, we may determine there is sufficient competition for no regulation at all. We will not classify these services. We refer to these as unclassified or unregulated distribution services.¹⁰

Some Qld metering services are fully contestable. Our view is that consumers have sufficient capacity, within contestable markets, to negotiate efficient prices for these services effectively. Therefore we will not classify these services. This means we will have no role in the pricing of these services over the next regulatory control period.

Our proposed approach is also not to classify emergency recoverable works. This will create the right incentives for distributors to recover the cost of emergency recoverable works from third parties that caused damage to the network.

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

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



Source: AER

Control mechanisms

Following on from service classifications, our determinations must impose pricing controls on direct control service prices and/or their revenues.¹¹ The form of control must be as set out in this F&A. The

¹⁰ In appendix B, our detailed table of service classifications, we use the term 'unregulated' specifically in relation to services provided by the distributors that are not distribution services. These services are outside our jurisdiction.

¹¹ NER, clause 6.2.5(a).

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.¹²

The rules require us to decide the control mechanism forms¹³ and propose 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.¹⁴ These include price schedules, caps on the prices of individual services, weighted average price caps, revenue caps, average revenue caps and hybrid control mechanisms.

In deciding on the form of control mechanism, the rules require us to have regard to specified factors.¹⁵ These include the need for efficient tariffs, administrative costs, previous regulatory arrangements and consistency. In light of the above alternatives and considerations, our proposed approach on the form of control mechanisms for the Qld distributors are:

- standard control services— revenue cap

We consider that a revenue cap best meets the factors set out under clause 6.2.5(c) of the rules. We consider that a revenue cap will result in benefits to consumers through a higher likelihood of revenue recovery at efficient cost, better incentives for demand side management, less reliance on energy forecasts and better alignment with the introduction 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. Therefore our proposed approach is to retain a revenue cap for the Qld distributors' standard control services.

- 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.¹⁶ 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:¹⁷

- encourage appropriate levels of service quality

¹² NER, clause 6.12.3(c).

¹³ NER, clause 6.2.5(b).

¹⁴ NER, clause 6.2.5(b).

¹⁵ NER, clauses 6.2.5(c) and 6.2.5(d).

¹⁶ 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.

¹⁷ AER, *Electricity distribution network service providers, Service target performance incentive scheme*, June 2008, p. 2; AER, *Expenditure incentives guideline*, 29 November 2013.

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

We outline below our proposed approach on the application of each scheme to the Qld distributors.

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 the Qld distributors in the next regulatory control period with ± 2 per cent financial reward or penalty based on whether the Qld distributors meet the STPIS targets. We will not apply the guaranteed service level (GSL) component as the Qld distributors are subject to a jurisdictional GSL scheme.¹⁸

Efficiency benefit sharing scheme

The efficiency benefit sharing scheme (EBSS) aims to provide a continuous incentive for distributors to pursue efficiency improvements in operating expenditure (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 the new EBSS to the Qld distributors in the next regulatory control period.

Capital expenditure sharing scheme

The capital expenditure sharing scheme (CESS) provides financial rewards for distributors whose capital expenditure (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 the Qld distributors 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

¹⁸ Electricity Industry Code (Qld).

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

Our proposed approach is to continue to apply the DMIS to the Qld distributors for the next regulatory control period. As we intend the Qld distributors' standard control services to 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 each distributor's 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, we propose setting the DMIA at \$5 million in total over five years.

Small-scale incentive scheme

The rules state that we may develop a small-scale incentive scheme.¹⁹ We have not developed this scheme. Therefore, our proposed approach is not to apply this scheme to the Qld distributors in the next regulatory control period.

Application of the expenditure forecast assessment guideline

In December 2013 we published our expenditure forecast assessment guideline for electricity distribution (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 the Qld distributors in the next regulatory control period.

The expenditure assessment guideline outlines a suite of assessment/analytical tools and techniques to assist our review of the Qld distributors' regulatory proposals. We intend to apply all the assessment tools set out in the guideline.

Depreciation

Changes to the rules require us to state our approach to calculating depreciation when we roll forward the Qld distributors' regulatory asset base (RAB) for the 2020–2025 regulatory control period. Our proposed approach is to use forecast depreciation to establish the RAB as at 1 July 2020.

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

Ergon Energy's request

In requesting we replace the current F&A, Ergon Energy asked us to address a range of additional matters. These included regulatory issues, matters related to the end of transitional regulatory arrangements and issues relating to revenue adjustments and capital contributions.

¹⁹ NER, clause 6.6.4.

We will address a number of Ergon Energy's issues within our distribution determination rather than as part of our F&A. For issues we can address in the F&A, we have set out our proposed approach and reasons. We will address remaining issues as part of our normal consultation with the distributors, undertaken before they must submit regulatory proposals for our consideration.

Dual function assets

Dual function assets are high voltage transmission assets forming part of the distribution network. Where a network service provider owns, controls or operates dual function assets, we are required to decide whether to treat the assets as transmission or distribution assets.²⁰

Neither Energex nor Ergon Energy currently own, control or operate any dual function assets. This is because there is a permanent derogation in the rules in relation to the definition of 'transmission network' in Queensland.²¹ Therefore, our decision is that we are not required to, and will not make any determination under the rules regarding dual-function assets.²²

²⁰ NER, clause 6.8.1(b)(1)(ii).

²¹ NER, clause 9.32.1(b).

²² NER, clauses 6.8.1(b)(1)(ii) and 6.25(b).

Part B: Attachments

1 Classification of distribution services

This attachment sets out our proposed approach to the classification of distribution services provided by Energex and Ergon Energy for 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 prices²³
- allow parties to negotiate services and prices and only arbitrate disputes if necessary, or
- do not regulate at all.

If we control prices directly, classification further determines whether distributors recover service costs from all customers or only those benefiting directly from specific services.²⁴

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, of 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 the classification as set out in this F&A.²⁵

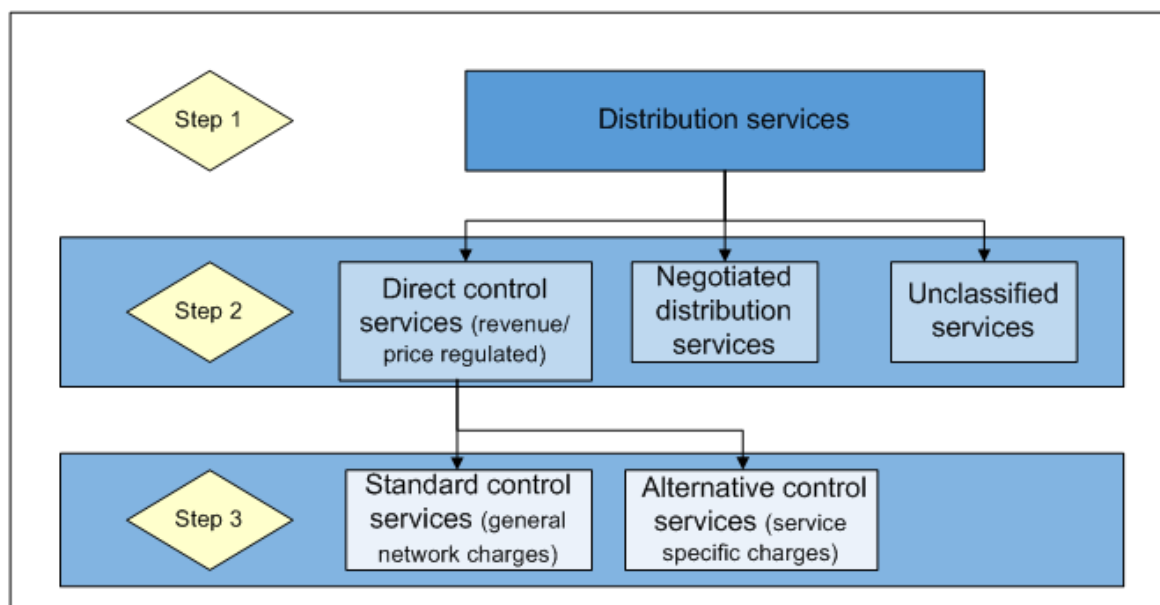
The rules set out a three step classification process we must follow. We must consider a number of specified factors at each step. Figure 2 outlines the classification process under the rules.

²³ Control mechanisms available for each service depend on their classification. Control mechanisms available for direct control services are listed by clause 6.2.5(b) of the 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.

²⁴ 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.

²⁵ NER, clause 6.12.3(b).

Figure 2: Distribution service classification process



Source: AER.

As illustrated by figure 2 above:

- 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.'²⁶ A distribution system is defined as 'a distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system'.²⁷
- 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 distributors will recover the cost of providing services. Distributors recover standard control service costs by averaging them across all customers using the shared network. In contrast, distributors will charge a specific user benefiting from an alternative control service. Alternative control classification is akin to a 'user-pays' system. The whole cost of the service is paid by those customers who benefit from the service.

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

²⁶ NER, chapter 10, glossary.

²⁷ NER, chapter 10, glossary.

- Negotiating distribution service criteria²⁸—sets out the criteria distributors are to apply in negotiating the price, and terms and conditions, under which they supply distribution services. We will also apply the negotiating distribution service criteria in resolving disputes.
- Negotiating framework²⁹—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 relates to each service within the group. Our proposed approach is to group distribution services provided by the Qld distributors as:

- network services
- connection services
- metering services
- ancillary network services
- public lighting services.

We consider each service falling within the above service groups is a distribution service.³⁰ They are services provided by means of, or in connection with, a distribution system.³¹

We propose to classify Energex and Ergon Energy's distribution services consistently. Distribution services provided by both distributors will have the same classification. Figure 3 summarises our proposed classification of the Qld distributors' distribution services. This section summarises our proposed approach to the classification of each service group.

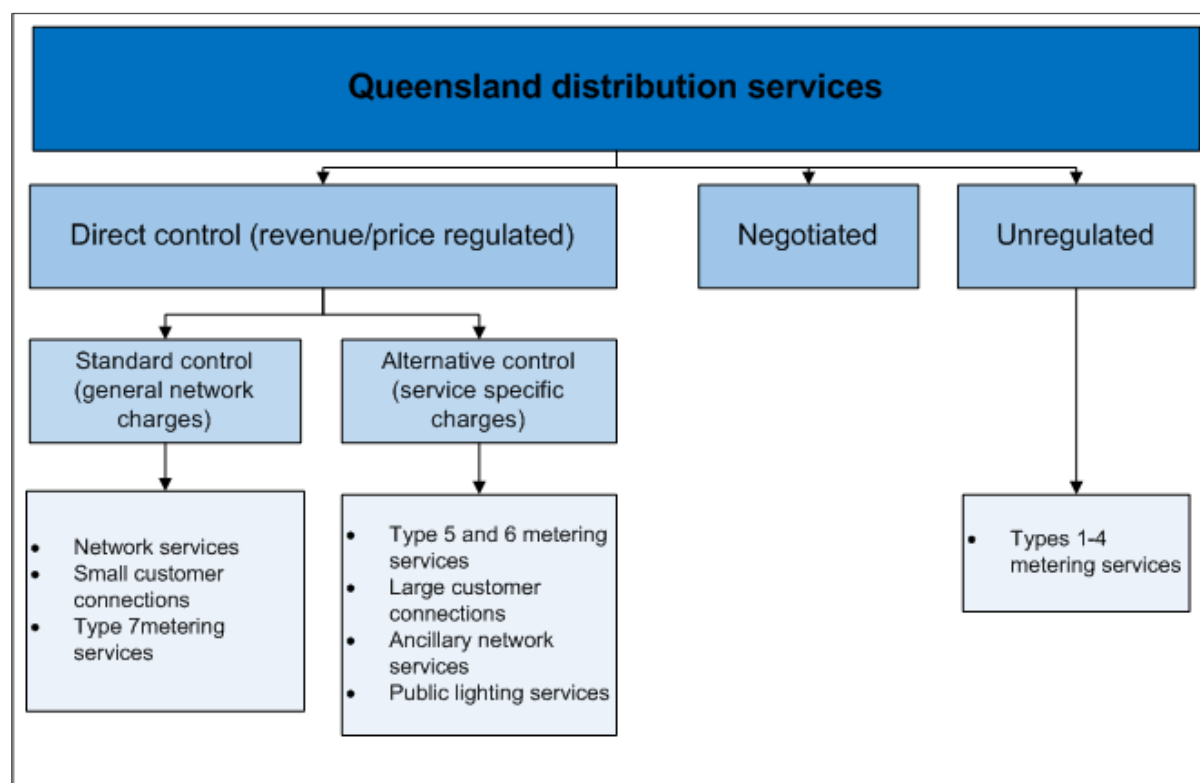
²⁸ NER, clause 6.7.4.

²⁹ NER, clause 6.12.1(15).

³⁰ See Appendix B for a list of each distribution service falling within the groups set out above.

³¹ NER, chapter 10, 'distribution system'.

Figure 3: AER's proposed classification of Qld distribution services



Source: AER

Network services are at the core of what an electricity distributor does, including constructing and maintaining those parts of the electricity network that everyone uses—that is, the shared distribution network. Energex and Ergon Energy provide network services in their respective geographic areas under exclusive distribution authorities, issued by the Qld Government. This restriction on competition exists because 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.

A distributor's broad customer base uses network services through a shared network, provided by distributors under monopolistic conditions. Therefore, we classify network services as standard control services so distributors recover the cost of providing network services from across their broad customer base. The lack of effective competition in the provision of network services gives further weight to classifying network services as standard control services.

Connection services relate to connecting new customers to the shared network. Connections are grouped into two broad categories: large customer connections and small customer connections. In Qld, we currently classify large customer connections as alternative control services. We propose to retain this approach.

We currently classify small customer connections as standard control services.³² We propose to retain the current approach, at this time. However, we consider there are potential benefits from an

³² Generally, small customers are those connected under the Standard Asset Connection threshold in the distributor's pricing proposal.

alternative control classification. In addition to establishing price transparency and a user-pays approach, an alternative control classification would facilitate contestability in the provision of small customer connections in future. While we are currently unable to foresee how contestability may work in practice, we may reconsider our classification approach if the Qld Government indicates it will establish contestability before or during the 2015–20 regulatory period.

Ancillary network services and some metering services are provided on an 'as needs' basis, requested by specific customers. Therefore, we set charges to allow distributors to recover the full cost of such services from customers that use them. Our proposed approach is to classify these services as alternative control. We propose to change the classification of simple type 5 (interval) and 6 (accumulation) metering services from standard control to alternative control. Doing so will mean small customers will pay for metering services they actually use. Under the current standard control classification, the metering charges customers pay may not correspond to the cost of the services they use. Changing to an alternative control classification for type 5 and 6 meters will also allow customers to purchase advanced metering infrastructure (AMI), or smart meters, without paying for metering twice.

Public lighting is currently an alternative control service in Qld. Our proposed approach is to retain this classification because public lighting services are provided to specific customers—usually local government councils.

A negotiated distribution service is a classification that reflects a light handed approach to regulation. Service providers and prospective users negotiate services and prices according to a framework set out in the rules. We are available to arbitrate if necessary. This classification relies on both parties possessing sufficient market power to effectively negotiate. At this time, we propose not to classify any Qld distribution services as negotiated services. In our preliminary positions F&A we noted the possibility of classifying large customer connections and Energex's public lighting services as negotiated services.³³ However, having taken submissions into account, we consider the potential benefits associated with such changes are currently outweighed by the negatives.

Finally, some distribution services are contestable. An example is the provision of smart meters. There are no legislative barriers to entry by third parties and alternative providers compete in a market to provide smart meters to customers. We think customers have sufficient market power to negotiate efficient prices for the provision of smart meters. We therefore propose not to classify them. This means we would continue to have no role in pricing the provision of smart meters over the next regulatory control period.

We also propose to not classify 'emergency recoverable works', though not for reasons relating to their contestability. Emergency recoverable works relate to the repair of the network after an identifiable third party has caused damage. This third party is liable at common law for the costs of repair. We consider that by not classifying this service we will establish the right incentives for distributors to recover costs from responsible parties.

1.2 AER's assessment approach

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

³³ AER, *Framework and approach preliminary positions paper*, December 2013, pp. 27, 38.

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.³⁴ We have reproduced these at appendix C. The form of regulation factors broadly include, amongst other things, the presence and extent of barriers to entry by alternative providers and whether distributors possess market power in provision of the services. The rules also require us to consider the previous form of regulation applied to services, the desirability of consistency with the previous approach and any other relevant factor.³⁵

For services we intend to classify as direct control services, the rules require us to have regard to a further range of factors.³⁶ Broadly, these include the potential to develop competition in provision of a service and how our classification may influence that potential. Also, whether the costs of providing the service are attributable to a specific person. And, the possible effect of the classification on administrative costs.

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

- 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 for classification and our reasons. In turn, this section deals with:

- network services
- connection services
- metering services
- ancillary network services
- public lighting.

Before addressing each of the service groups listed above, we first address how we have developed the service groupings to which we will apply our classification approaches.

1.3.1 Service group descriptions

We consider our service group descriptions should allow stakeholders to understand our proposed classifications while avoiding unnecessary detail. The table of service classifications attached to our preliminary positions F&A³⁸ provided detail where required for clarity, but avoided being an exhaustive list of activities that are actually components of services. Were we to set out each activity undertaken as a component of each distribution service we classify, the documentation would become unwieldy.

³⁴ NEL, clause 6.2.1(c); NEL, s. 2F.

³⁵ NEL, clause 6.2.1(c).

³⁶ NEL, clause 6.2.2(c).

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

³⁸ AER, *Preliminary positions paper F&A for Qld*, December 2013, appendix B.

Our approach to defining services in the preliminary positions F&A classifications table was supported by Energex.³⁹

Ergon Energy submitted that it prefers us to classify only high level, or generic, descriptions of distribution services.⁴⁰ In effect, Ergon Energy seeks flexibility to allocate services to the high level service headings it considers are appropriate. We consider Ergon Energy's proposed approach would create uncertainty about our proposed service classifications. The value of setting out our proposed service classifications in the F&A, ahead of the distributors submitting regulatory proposals, is in the clarity it provides to all parties. Ergon Energy's proposed service classification approach would erode this value.

Ergon Energy also submitted that every service the distributor is 'obliged to provide in its role as a distributor should be subject to direct control because it is the monopoly service provider'.⁴¹ We do not agree with Ergon Energy's proposition that any service a distributor is 'obliged to provide' should be classified as either standard control or alternative control. The rules set out a range of factors we must have regard to in classifying distribution services. We may classify a service the distributors are required to provide as direct control, negotiated, or not classify it at all.⁴² Ergon Energy's view on service classification causes us concern that its proposal for us to classify high level service groups would lead to inappropriate service classifications.

Energex supported our approach to defining service groups. We consider the level of detail in our preliminary positions classifications table balances the need for clarity while avoiding unnecessary detail. Therefore, our amendments to the classifications table are limited to changes we consider will assist the distributors, customers and other stakeholders to understand our proposed classifications. We consider that taking a consistent approach to service group descriptions for both distributors will assist customers and other stakeholders. Ergon Energy has not provided compelling arguments for us to apply a different approach to it, compared to Energex. Further, because our classification approaches for Ergon Energy are consistent with our approaches for Energex, we have produced a single classifications table as appendix B to this F&A paper. Ergon Energy submitted, in tabular form, detailed comments in response to our table of service classifications published with our preliminary positions paper F&A. As appendix D to this F&A paper, we set out our response to Ergon Energy's detailed comments.

1.3.2 Network services

Distributors provide network services over a shared distribution network to all customers connected to it.⁴³ Customers use or rely on network services on a daily basis. Examples include the construction and maintenance of the shared network.

We propose 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.

The *Electricity Act 1994* (Qld) prevents a person from distributing and supplying electricity unless they hold an authority permitting them to do so.⁴⁴ Additionally, customers cannot source network services

³⁹ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 2.

⁴⁰ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 24 and

⁴¹ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, pp. 24 and 39.

⁴² For example, we propose not to classify 'emergency recoverable works'.

⁴³ NER, chapter 10, definition of 'network service'.

in their district from external providers.⁴⁵ Energex and Ergon Energy each hold the only electricity distribution authority for their respective distribution areas.⁴⁶ These arrangements together provide a regulatory barrier, preventing third parties from providing network services.⁴⁷ Therefore, we consider that there is no market for network services for third parties to compete in. The Qld distributors possess significant market power due to the regulatory arrangements in place.⁴⁸ Therefore, we intend to classify network services as direct control services.

We must further classify direct control services as either standard or alternative control services.⁴⁹ We propose 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.⁵⁰ The absence of competition is due to the Qld distributors holding the only authorities to provide network services in each distribution area. There would be no material effect on administrative costs for us, the distributors, users or potential users because a standard control classification is consistent with the current regulatory approach.⁵¹ Also, we currently classify network services in all NEM jurisdictions as standard control services.⁵² And finally, distributors provide network services through a shared network, so cannot directly attribute the costs of these services to individual customers.⁵³ Energex supported our proposed approach.⁵⁴ Ergon Energy did not oppose our proposed approach.⁵⁵ Other submissions did not comment on this issue.

Load control services

Load control is the control of electricity consumption other than by customers themselves physically turning on and off electrical appliances. A common example of load control is use of off peak electricity for domestic hot water supply. To provide this service, the distributor installs a load control device at the customer's premises. Load control devices can also control pool pump operation and enable remote control of air conditioning units by customers or distributors. With the take-up of smart meter technology, a range of further load control related services will become possible, including remote load control.⁵⁶ These services may compete with load control services currently provided by the distributors.

In our preliminary positions F&A, we included 'scheduling and controlling the switching of controllable load for network services' as part of network services. We considered this service group description covered load control related to network operations and proposed to classify it as standard control. This means all customers would pay for the cost of a distributor providing these load control services to an individual customer. This is because effective load control can reduce the total amount of electricity required by customers at peak times and so avoid some network investment that would otherwise be required. This benefits all customers by keeping standard network charges lower than otherwise.

⁴⁴ Under s. 88A of the *Electricity Act 1994* (Qld), the right to supply electricity using a supply network within a distribution area is provided under a 'distribution authority', equivalent to a licence to operate.

⁴⁵ *Electricity Act 1994* (Qld), s. 41.

⁴⁶ Authorities are issued by the Director General of Qld's Department of Energy and Water Supply.

⁴⁷ This is relevant under the form of regulation factors; see NEL, s. 2F(a).

⁴⁸ This is a relevant form of regulation factor: NEL, s. 2F(d).

⁴⁹ NER, clause 6.2.2(c).

⁵⁰ NER, clause 6.2.2(c)(1).

⁵¹ NER, clause 6.2.2(c)(2).

⁵² NER, clause 6.2.2(c)(3).

⁵³ NER, clause 6.2.2(c)(5).

⁵⁴ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 19.

⁵⁵ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 24.

⁵⁶ Whereby customers, distributors or other parties may remotely switch load at any time.

Energex submitted that load control services commonly relate to the network and not to metering services.⁵⁷ Ergon Energy submitted that some load control services are network related and some are metering related.⁵⁸ The distributors raised this issue in the context of our proposed approach to unbundle type 5 and 6 metering services and classify these alternative control. The distributors sought confirmation from us that load control would remain a standard control service. We agree load control services relate to network operation and are not metering related. Therefore, we propose to retain load control within network services and classify it as standard control.⁵⁹

Ergon Energy further requested that we establish a new alternative control service for customer or retailer requested load control relays.⁶⁰ We consider this service relates to a request to upgrade an existing load control service. That is, it does not relate to a standard load control installation, nor standard maintenance or asset replacement. Rather, this service relates to an additional service, requested by the customer, outside the standard network service which we propose to classify as standard control. We agree with Ergon Energy (and Energex) that they should be able to charge a customer or retailer a fee for providing such a service on request. Therefore, we have added this service to our classifications table at appendix B. We consider this service is a distribution service. Because we have not seen evidence of significant competition in the provision of this service, we propose to classify the service as direct control.⁶¹ Because the service is provided to an identifiable customer, we propose to further classify it as alternative control.⁶²

Potential for contestability in load control services

Notwithstanding our proposed approach, there may be benefits from unbundling standard load control services entirely and separately classifying them as an alternative control service. By doing so, customers directly benefitting from load control services would see a price signal for the provision, installation and maintenance of load control devices. Standard network charges paid by all customers would be reduced. Unbundling load control from standard network charges would also facilitate the future introduction of contestability in the provision of load control services. Customers would be able to choose between multiple providers of load control devices and associated services, if those services became contestable.

We can envisage a future Qld electricity market in which load control services are traded by small business and residential customers, distributors, retailers and load control aggregation companies. In these circumstances, it would be inappropriate for our classification approach to restrict customers to load control services offered by the distributors alone. Load control trading is already occurring amongst large electricity users and other market participants. We consider the emergence of such a market amongst smaller customers is highly likely, if regulatory or legislative barriers are removed. A key barrier to competition is our current classification of load control services as standard control.

Were we to pursue this approach now, it would be new to the NEM, requiring careful consideration and consultation. To date, consumers and other stakeholders have not had an opportunity to consider or provide comment on reforms to the pricing and provision of load control services. We consider it is preferable to consult with stakeholders before undertaking such reforms.

⁵⁷ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 23.

⁵⁸ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 31.

⁵⁹ We have added network related load control to service groups for constructing, maintaining and operating the network. We have removed load control from metering related services. Energex proposed that we add load control to 'administrative support for network services', but we consider load control is not administrative in nature.

⁶⁰ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 36.

⁶¹ NEL, s. 2F(a).

⁶² NER, clause 6.2.2(c)(5).

We have not received a proposal for network related load control services to be unbundled and classified as alternative control. Nor do we propose to do so in this F&A. However, we consider the potential benefits from doing so may be significant. We are currently unable to foresee how unbundling load control services would work in practice. We intend to raise this again in the context of our issues paper for this distribution determination process, to be released after we receive the distributors' regulatory proposals. We urge all stakeholders to give consideration to these issues.

Emergency recoverable works

'Emergency works' relate to repairing the distribution network after damage to restore or maintain electricity supply. Repairing damage caused by a storm is an example of such works. 'Emergency recoverable works' relate to the distributors' 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 Qld distribution emergency recoverable works as alternative control services.

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

Given that these services are provided in connection with a distribution system, we consider emergency recoverable works are a distribution service. However, in terms of classification, we consider that emergency recoverable works are distinguishable from other network services. This is because the cost of these works may be recovered under common law. That is, the distributors can seek payment of their costs to fix the network from the parties responsible for causing the damage, through the courts if necessary. The rules set out a number of matters we must have regard to in classifying distribution services, including 'any other relevant factor'.⁶³ The manner of cost recovery is a relevant factor. This view is reinforced when it is considered in light of the National Electricity Objective (NEO). Broadly, the NEO requires us 'to promote the long term interests of consumers of electricity' with respect to the national electricity system (see footnote below for the full text of the NEO).⁶⁴ It is in the interests of electricity consumers that the costs of network repairs be recovered from the party(ies) responsible for the damage, rather than users of the network. For this reason, we propose not to classify emergency recoverable works.⁶⁵

By not classifying emergency recoverable works, distributors are not able to recover costs for these services from consumers. To be compensated for damage to the network caused by an identifiable party, distributors must seek to recover costs from that party. We consider this will establish the right incentives for Energex and Ergon Energy to pursue costs from parties responsible for damage to distribution network assets. Our proposed classification is also consistent with our approach to the classification of emergency recoverable works in NSW.⁶⁶

In response to our preliminary positions F&A, Energex and Ergon Energy submitted that emergency recoverable works should remain classified as a direct control service.⁶⁷ Ergon Energy further

⁶³ NER, clause 6.2.1(c)(4).

⁶⁴ *National Electricity (South Australia) Act 1996*, schedule National Electricity Law, section 7, which states 'The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to – (a) price, quality, safety, reliability and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system'.

⁶⁵ NER, clause 6.2.1(c)(4).

⁶⁶ 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.

⁶⁷ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 19.

proposed that it remain a network service and so be classified as standard control.⁶⁸ In support of their preferred approach, the distributors submitted that we had not sufficiently addressed the factors to justify departing from the current standard control classification. Energex submitted that we are required by the rules to focus on the distribution service rather than how related costs are recovered. Also, that an alternative control classification would be consistent with our current approach in Victoria.⁶⁹ Ergon Energy submitted that recovery of costs from responsible parties is difficult and that it incurs administrative costs in doing so, giving weight to a standard control classification.⁷⁰ Also, that there is not always an identifiable party in relation to network damage.

We are not persuaded by the arguments submitted by the distributors that we should change our proposed classification of emergency recoverable works. We have discussed above the relevance of cost recovery to our classification decision. The decision to classify emergency recoverable works in Victoria as an alternative control service was made in 2010. A more relevant classification decision is the approach we have taken in NSW, where we propose not to classify this service for the same reasons as our proposed approach to Energex and Ergon Energy.⁷¹ The NSW distributors supported our approach to not classify emergency recoverable works.⁷² We consider that in circumstances where the party responsible for damaging the network is not identifiable, related costs are not recoverable. Therefore, works to repair that damage would not be considered emergency recoverable works. Rather, they would be emergency works.

Distributors already incur administrative costs in recovering costs from parties responsible for damaging the network. We consider any further administrative costs associated with changing classification will be outweighed by the benefits to customers of not having to bear the costs of network repair where the distributor can recover them directly from the responsible parties.⁷³ That Energex and Ergon Energy may find it difficult to recover costs from some responsible parties is not justification for those costs to instead be recovered from electricity customers.

We consider that the cost of emergency recoverable works being recovered from parties responsible for damaging the network is clearly more appropriate than the present classification, under which customers pay.⁷⁴ Therefore, we consider not classifying emergency recoverable works for both Energex and Ergon Energy is clearly more appropriate than the present classification approach.⁷⁵

1.3.3 Connection services

Chapter 10 of the rules defines connection services.⁷⁶ Put simply, a connection service refers to the services a distributor, or alternative service provider (ASP),⁷⁷ performs to:

- connect a person's home, business or other premises to the electricity distribution network

⁶⁸ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 30.

⁶⁹ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 19.

⁷⁰ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 29.

⁷¹ AER, *Stage 1 Framework and approach - Ausgrid, Endeavour Energy and Essential Energy*, March 2013, p. 20.

⁷² NSW distributors, *Response to the AER's preliminary framework and approach paper*, August 2012, p. 1.

⁷³ NER, clause 6.2.2(c)(2).

⁷⁴ Under NER, clause 6.2.1(d), we must only change classification of a service where a different classification 'is clearly more appropriate'.

⁷⁵ NER, clause 6.2.1(d).

⁷⁶ NER, chapter 10 defines connection services, broadly, as consisting of entry services and exit services. An entry service is a service provided to serve a generator or group of generators, or a network service provider or group of network service providers, at a single connection point. An exit service is a service provided to serve a distribution customer or a group of distribution customers, or a network service provider or group of network service providers, at a single connection point.

⁷⁷ An ASP is someone other than Ergon Energy or Energex who performs connection work when it is contestable. That is, an ASP is appointed to perform the connection work by a customer. We consider an ASP is not a contractor or other third party appointed by a distributor to perform work for which the distributor is responsible.

- get more electricity from the distribution network than is possible at the moment
- extend the network to reach a person's premises.

We consider it possible to separate connection services into clearly identifiable components. Table 3 lists our proposed definitions of each connection type together with our proposed classification of each type.

Table 3: AER's proposed approach for Qld connection services

Service group	Current classification	AER proposed classification
Small customer connections* – Design, construction, commissioning and energisation of connection assets for small customers. ⁷⁸	Standard control	Standard control
Large customer connections – Design and construction of connection assets for large customers. ⁷⁹	Alternative control	Alternative control
Commissioning and energisation of large customer connections	Standard control	Alternative control
Real estate development connections	Standard control	Alternative control
Operate and maintain connection assets	Standard control	Standard control
Pre connection services – general enquiry services	Standard control	Standard control
Pre-connection services – connection application & consultation services	Alternative control	Alternative control
Temporary connections	Alternative control	Alternative control
Connection management services (post connection)	Alternative control	Alternative control
Accreditation of alternative service providers and approval of their designs, works and materials	Standard control / alternative control	Alternative control
Removal of network constraint for embedded generator	Standard control	Alternative control

* Note: A distributor may ask a small customer seeking a connection to make a further financial contribution if it expects the cost of the connection to exceed the distributor's expected regulated revenues from the connection. See Appendix B, an element of 'connection service management'—'provision of connection services above minimum requirements'.

Source: AER

We consider each connection type separately below.⁸⁰

⁷⁸ Generally, small customers are those who connect under the Standard Asset Connection tariff class in the distributor's pricing proposal.

⁷⁹ Generally, large customers are those who connect under the Individually Calculated Customer (ICC), Connection Asset Customer (CAC) and Embedded Generator (EG) tariff classes as per the distributor's pricing proposal.

⁸⁰ NER, clauses 6.2.1 and 6.2.2 govern our classification decisions for these connection services.

Small customer connections

We propose to classify small customer connections as standard control services. However, the distributors and Qld Government may provide information to support a change in classification approach in our draft determination.

We currently classify small customer connections as direct control and standard control services. This means the cost of connecting a small customer is included in the general network charges paid by all customers. If a small customer connection costs more than the estimated value of that customer's standard network charges, the distributors are able to charge an additional fee. This is called a 'capital contribution' and is set at a level to make up the difference between standard network charges and the actual costs of connection. In our preliminary positions F&A, we set out our preliminary position to retain the current standard control classification.⁸¹ In response, Energex suggested that small customer connections be reclassified as alternative control services.⁸²

Under Energex's proposed approach, newly connecting small customers would pay a separate fee, regulated by us, for their connection service. As a consequence, standard network charges would be reduced. In support of its proposal, Energex submitted that an alternative control classification would facilitate a user pays approach and the future development of competition in the design and construction of small customer connection assets.⁸³ Energex also submitted that an alternative control classification would be consistent with our reasons for classifying type 5 and 6 metering services as alternative control.

We agree with Energex that an alternative control classification would lead to price transparency and to a user pays approach. We also agree that an alternative control classification would facilitate contestability. However, our classification is not the key determinant of contestability for these services. Currently, there are no alternative service providers for small customer connection services. Allowing alternative providers would require a policy decision by the Qld Government. Were we to classify small customer connections as alternative control services, a very significant barrier to contestability would be removed, but introduction of contestability would still require the Qld Government to change its current policy.⁸⁴

We consider the benefits of contestability are potentially significant. We expect efficiencies could be realised by removing the distributors' monopoly on undertaking small customer connections and allowing other providers to compete. While individual customers would experience a new charge for their connection, we expect that the total cost of providing the network would be reduced by the extent of efficiencies realised through competition. It would also give small customers a choice in who performs their connection service—a choice they currently do not have. And there may be benefits in terms of the timeliness of performing a small customer connection by allowing a broader range of providers to perform the service.

In response to our preliminary positions F&A, the director general of the Qld Department of Energy and Water Supply (DEWS) submitted:⁸⁵

⁸¹ AER, *Preliminary positions paper F&A for Qld*, December 2013, p. 27.

⁸² Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 30.

⁸³ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 30.

⁸⁴ Under NEL, s. 2F(a), the presence and extent of barriers to entry to the market for a service is a factor we must consider in classifying it. We consider this is the key form of regulation factor affecting this service.

⁸⁵ Department of Energy and Water Supply, *Submission to the AER's Preliminary framework and approach for Energex and Ergon Energy*, 25 February 2014, p. 1.

The Queensland Government is committed to identifying opportunities for the private sector to compete for what are currently monopoly services, where this is effective and efficient. The optimal extent for introducing competition for small customer connections is one area warranting further examination. My Department is currently considering the implications for customers of contestability in small customer connections.

We consider the DEWS submission leaves open the possibility that the Qld Government may introduce contestability in small customer connections, but is not definitive. On this basis, we are not sufficiently confident that, were we to change our classification approach, contestability would be introduced. If we classify small customer connections as alternative control, but the service does not become contestable, customers will face a new service fee but there will be no other benefits. In the absence of a move to make these services contestable, we consider there is not adequate reason to justify a change from the current classification.⁸⁶ Therefore, we propose to retain the current standard control classification for small customer connections. Should the Qld Government indicate before our determination that it intends to establish contestability in the provision of small customer connections before or during the 2015–20 regulatory control period, we would reconsider our classification approach. In effect, a Qld Government policy statement on contestability may constitute an unforeseen circumstance, justifying a change in classification.⁸⁷

Should the Qld Government introduce contestability for small customer connections, it may also consider establishing an independent accreditation scheme for alternative service providers of connection services. Currently, the distributors accredit alternative service providers. This means the distributors act as gatekeepers for their competitors. There may be other potential or actual barriers to alternative service providers effectively competing to perform connections. The Qld Government could review the current arrangements with a view to undertaking pro-competition reforms.

We also consider customers and other stakeholders have not had opportunity to properly consider a possible change in classification approach. We did not propose an alternative control classification in our preliminary positions F&A, meaning interested parties were not invited to make submissions on the issue. We consider this gives further weight to retaining a standard control classification for now, but to leave open the possibility of changing our approach in our draft determination. We urge Energex to use this time to consult with its customers on its proposed change. We will take consultation into account when considering our classification decisions in our draft determination.

We also note that there is more than one way to increase the scope for contestability in the provision of connection services. For example, it may be possible to redefine large customer connections so that a larger range of connection types become subject to the existing alternative control classification for large customer connections. This could be done by lowering the threshold for a large customer connection service. Under this approach, the benefits of contestability could be partially realised while connection services for typical (or basic) residential customers remain standard control. Such an approach may alleviate concerns that residential customers with low or fixed incomes may be unfairly penalised by the establishment of a new alternative control service fee. However, at this stage such an approach has not been proposed. Nor do we propose this approach now. We consider this may be a model the distributors, the Qld Government, consumers and other stakeholders wish to consider in the context of the distributors' regulatory proposals.

We consider that the commissioning and energisation of a small customer connection is part of the connection service. Therefore, we have grouped commissioning and energisation with small customer

⁸⁶ NER, clause 6.2.1(d)(1) requires that we should not depart from a previous classification unless a different classification is clearly appropriate.

⁸⁷ Under clause 6.12.3(b) of the rules, the distribution service classifications must be as set out in this F&A unless we consider that unforeseen circumstances justify us departing from it.

connections and propose to classify the full service as a standard control service. Should we change our approach in our draft determination, to classify small customer connections as alternative control, we will consider unbundling commissioning and energisation to separately classify this service as alternative control. We would do this because the distributors would be required to commission and energise small customer connections performed by alternative service providers. The distributors should in those circumstances be able to charge connecting customers for this service. As a consequence, the cost of commissioning and energising small customer connections would be removed from standard network charges paid by all customers.

We further consider that, once completed, a connection becomes part of the shared distribution network. That is, Energex and Ergon Energy will operate and maintain connection assets as part of their routine maintenance of the shared network. Therefore, our proposed approach is to classify the operation and maintenance of connection assets as direct control and standard control services.

We note that connecting micro embedded generators, 30 kVA or smaller, is currently classified as a standard control service. This is because micro embedded generators are grouped by the distributors with other small connections, in the Standard Asset Connection class. In principle, we consider the costs incurred by distributors in connecting embedded generators should be recovered from the customers benefitting from this service. That is, we think there is scope to classify the connection of micro embedded generators as an alternative control service. However, should we change our classification approach for small customer connections to alternative control, no further changes to classification of connecting small generators would be needed. This is because all small customers, including micro embedded generators, would pay an alternative control service charge for their connection costs. Because there is significant doubt at this point in time as to our classification approach for small customer connections, we are currently unable to foresee whether any action is required to separate micro embedded generators and separately classify this service as alternative control.

Large customer connections

We propose to retain the current classification of large customer connections as direct control and alternative control services.⁸⁸ This is a relatively new arrangement. At the last Qld distribution reset we changed the classification of large customer connections to alternative control from standard control.⁸⁹ At the same time the Qld Government made these services contestable.⁹⁰ We therefore have only around three years of experience with large customer connections as contestable services.

In our preliminary positions F&A we set out our nominal position to retain the current direct control classification for large customer connections.⁹¹ We noted that competition in the provision of large customer connections is still recent.⁹² As the service is provided to specific customers and competition appears to be developing, we further proposed to retain the current alternative control classification.⁹³ We also noted it may be possible to classify large customer connections as negotiated services, allowing prospective customers to negotiate prices with the distributors.

⁸⁸ AER, *Framework and approach paper – classification of services and control mechanisms – Energex and Ergon Energy 2010–15*, August 2008, p. 13.

⁸⁹ AER, *Framework and approach paper – classification of services and control mechanisms – Energex and Ergon Energy 2010–15*, August 2008, p. 20.

⁹⁰ NEL, s. 2F(a).

⁹¹ AER, *Preliminary positions paper F&A for Qld*, December 2013, p. 27.

⁹² NEL, ss. 2F(a),(d) and (g).

⁹³ NER, clause 6.2.2(c)(1)(5).

Under a negotiated service classification, prospective customers and the distributors would negotiate under a framework established by the rules. We would be available to arbitrate if necessary. Were we to classify large customer connections as negotiated, the rules would obligate Energex and Ergon Energy to each prepare a negotiating framework.⁹⁴ Amongst other things, these would specify that the distributor must negotiate in good faith, provide prospective service users with enough information for them to negotiate and establish a dispute resolution process.⁹⁵

Energex submitted that it prefers us not to classify large customer connections.⁹⁶ Were we to adopt Energex's proposed approach, we would have no role in determining, nor arbitrating, the price for which Energex performs large customer connection. That is, customers would not have the safeguard of a regulated price for Energex to undertake this service. Nor would customers have access to us to resolve a dispute. Energex further submitted that, should we decide to classify large customer connections, we should retain the current alternative control classification. Classifying large customer connections as a negotiated service is Energex's least preferred outcome.

Ergon Energy submitted that it prefers us to retain the current alternative control classification for large customer connections.⁹⁷ Should we decide to change our classification approach, Ergon Energy prefers us not to classify the service rather than classify large customer connections as a negotiated service. We did not receive submissions from current or prospective users of large customer connection services, nor alternative providers, in response to our preliminary positions F&A.

A key consideration for us in deciding whether to classify a distribution service is the extent and effectiveness of competition in the market for the service.⁹⁸ We also take into account the existence and extent of any barriers to entry by alternative service providers.

Energex submitted that alternative service providers performed around one third of large customer connections in its distribution area in 2012–13.⁹⁹ Energex further submitted that a higher proportion of large customer connections are being performed by alternative providers in the current year. Ergon Energy also submitted that around one third of its large customer connections currently under way are being performed by alternative providers.¹⁰⁰ The current alternative control classification and the Qld Government's decision to make this service contestable seem to have been successful, though given the short period of time, how successful remains unclear.¹⁰¹ In most markets, a provider with a market share of two thirds would be considered to hold a dominant market position.

After only three years of large customer connections being contestable, we consider the market is still developing. There may be types of large customer connections for which the distributors retain market power, such as those involving network augmentation.¹⁰² There may also be particular geographic regions where the distributors retain market power.¹⁰³ With only around a third of large customer connections being provided by alternative providers we consider it is premature to not classify large customer connections. We also retain concerns around the current process for accrediting alternative

⁹⁴ NER, clause 6.7.5.

⁹⁵ NER, clause 6.7.5(c).

⁹⁶ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 29.

⁹⁷ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, pp. 24 and 39.

⁹⁸ NEL, s. 2F.

⁹⁹ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 29.

¹⁰⁰ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 25.

¹⁰¹ NEL, s. 2F(d).

¹⁰² As the only authorised entities able to perform augmentation work on their own networks, the distributors may be able to perform a joint connection-augmentation project cheaper than an alternative service provider due to economies of scale.

¹⁰³ Such as in remote regions where the distributors are able to maintain resources, financed by standard network charges, giving the distributors a competitive advantage over alternative service providers that must move resources to the area from elsewhere.

service providers for large customer connections.¹⁰⁴ Energex and Ergon Energy themselves accredit other parties to perform large customer connections in their respective distribution areas. That is, the distributors accredit their prospective competitors. In our last Qld distribution determination we considered the barrier to competition raised by the accreditation process was only a limited one.¹⁰⁵ Therefore, we were comfortable to move from a standard control classification to alternative control. However, in the present context of potentially moving away from a direct control classification we think this barrier is more significant.

We can contrast the current circumstances in Qld with other states. By comparison, NSW has a well-developed independent process for accrediting alternative service providers and a competitive environment for the provision of premises connection services.¹⁰⁶ Moreover, in most circumstances NSW distributors do not perform connections work. Hence, market power issues are much less likely to arise when we consider how to classify NSW large customer connections. In Qld, an independent accreditation system for alternative providers of large customer connections would give significant weight to the case for not classifying this service. To date, the Qld Government has not indicated it will establish an independent accreditation system.

We consider classifying large customer connections as a negotiated service may be a reasonable first step towards, potentially, not classifying this service in future. However, we recognise that classifying large customer connections as negotiated would also incur costs.¹⁰⁷ The distributors do not currently have a negotiation framework because they do not currently operate any services classified as negotiated. Therefore, were we to classify a service as negotiated, the distributors would be required to establish a negotiating framework. In turn, this would require stakeholder consultation and dedication of distributor and stakeholder resources.

Ergon Energy submitted that the incremental benefits of a negotiated classification are not clear.¹⁰⁸ Origin supported an alternative control classification.¹⁰⁹ In the context of receiving no customer support for a negotiated classification and the distributors opposing such an approach, we consider it is appropriate to conclude that the potential benefits are limited. We therefore agree with the distributors not to classify large customer connections as a negotiated service. On balance, we consider retaining the current alternative control classification for large customer connections, for both Energex and Ergon Energy, is preferable.

In addition to the design and construction of a large customer connection, commissioning and energisation of the connection assets is required. We consider that the commissioning and energisation of a large customer connection is part of the service provided to a specific customer. Therefore, our proposed approach is to also classify this service alternative control, consistent with the classification of large customer connections. However, we have classified commissioning and energisation separately because large customer connections may be performed by alternative service providers, requiring separate commissioning and energisation by Energex or Ergon Energy. The distributors should be able to charge for this service. As a consequence, standard network charges will be reduced.

¹⁰⁴ As noted, we must consider barriers to entry under NEL, s. 2F(d).

¹⁰⁵ AER, *Framework and approach paper – classification of services and control mechanisms – Energex and Ergon Energy 2010-15*, August 2008, p. 17.

¹⁰⁶ *Electricity Supply Act 1995* (NSW).

¹⁰⁷ NER, clause 6.2.2(c)(2).

¹⁰⁸ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 25.

¹⁰⁹ Origin, *Framework and approach for Energex and Ergon Energy for period commencing 1 July 2015*, 13 February 2014, p. 1.

Ergon Energy submitted that it is considering whether some other services associated with large customer connections could be not classified.¹¹⁰ As an example, it referred to environmental and cultural heritage assessment and community engagement. It said that there is effective competition for 'the associated pre-connection and support services that Ergon Energy can otherwise provide'.¹¹¹ We consider Ergon Energy has insufficiently described its proposal that we could not classify some services associated with large customer connections. On the basis of information we have available, we are not able to form a view on this issue. As such, we propose to retain the current classification approach.

Ergon Energy asked us to clarify how embedded generator connections should be treated.¹¹² In particular, Ergon Energy sought clarity on embedded generators between 30 kVA and 1 MW in size. That is, larger than a micro embedded generator but not large enough to currently be treated as a large customer. In response to Ergon Energy's query, we consider the distributors should charge embedded generators between 30 kVA and 1 MW the full cost of their connection. As a large customer connection, this service will be subject to an alternative control service charge. To make this clear, we have made this point in our table of service classifications, provided at appendix B.

Large customer connections – shared network augmentation

In response to our preliminary positions F&A, Ergon Energy submitted that we should consider establishing a new alternative control service for shared network augmentation required because of a new large customer connection.¹¹³ Ergon Energy proposed that we classify such a service at a high level. It further proposed that we allow the distributors to submit with their regulatory proposals the principles they would apply to determine when such costs would be payable by a newly connecting large customer.

Works to augment the existing network (as opposed to extending the network to a new customer) are generally treated as shared costs because augmentation typically benefits a group of customers. However, we do not wish to preclude the possibility of a customer contributing to augmentation required because of its new connection. We are open to establishing an alternative control service for augmentation of the existing network that is required because of a new large customer connection, but there is a barrier to our adoption of such an approach at this time. At this point, without knowing the detailed arrangements for identifying when network augmentation costs could be directed to a newly connecting large customer, we are unable to see how such a mechanism would work. We invite Ergon Energy (and Energex) to set out such details in its connections policy. We expect that each distributor will submit connections policies to us with their regulatory proposals. At that time we may consider the submitted details to have been unforeseeable.¹¹⁴ We may then consider making adjustments in our preliminary determination to create a new alternative control service for network augmentation related to a large customer connection.

Pre-connection services

Pre-connection services include both the provision of general information about connections to the broad customer base and services provided to specific customers on request.

¹¹⁰ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 28.

¹¹¹ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 28.

¹¹² Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 47.

¹¹³ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 38.

¹¹⁴ NER, clause 6.12.3(b).

Provision of general information about connections is a service provided to the broad customer base. Only the Qld distributors are able to provide these services to customers.¹¹⁵ Therefore, our proposed approach is to classify this as a direct control service. It would be difficult, if not impractical, for distributors to separately identify and charge specific customers benefitting from this service.¹¹⁶ As such, we further propose to classify pre-connection services as standard control services. This is consistent with the current classification.

Other pre-connection services are required by specific customers. These include consultation about a potential new connection and may include the distributor undertaking site inspections. In the context of a large customer connection, the distributor may be required to assess and approve connection designs made by alternative service providers. As these services are part of a distributor's role as a monopoly service provider, our proposed approach is to classify them as direct control services.¹¹⁷ Because these services may be attributable to specific customers, or prospective customers, we further propose to classify them as alternative control services.¹¹⁸

Real estate developments

We propose to separately classify real estate development (subdivisions) connections as direct control and alternative control services. While this is a change from our current standard control classification, for real estate developers this represents a continuation of current practice.¹¹⁹ This is because, under Qld jurisdictional arrangements, developers currently make a capital contribution for the full value of their connection service.¹²⁰ Equally, as an alternative control service, real estate developers will still pay the full cost of connecting to either the Energex or Ergon Energy networks.

In submissions, both Energex and Ergon Energy proposed we classify real estate development connections as alternative control.¹²¹ The distributors further proposed we separately classify real estate development connections to provide clarity that the current approach will continue if the Qld Government introduces the National Energy Customer Framework (NECF). Under NECF, the distributors would be required to apply our Connection Charge Guidelines, under which they must contribute to the cost of performing new connections.¹²² In separately classifying real estate connections as alternative control, we will make clear that the current arrangements will continue whether NECF is introduced or not.

We consider connection services for real estate developments are a distribution service. We further consider that the current effect of the jurisdictional arrangements, under which developers fund the full cost of their connection, should be maintained.¹²³ Therefore, in light of the potential introduction of NECF, classifying real estate connections as alternative control is clearly more appropriate than retaining the current standard control classification.¹²⁴ Also, the cost of real estate development

¹¹⁵ NEL, s. 2F(a).

¹¹⁶ NEL, clause 6.2.2(c)(5).

¹¹⁷ NEL, s. 2F(a).

¹¹⁸ NER, clause 6.2.2(c)(5).

¹¹⁹ AER, *Framework and approach paper – classification of services and control mechanisms – Energex and Ergon Energy 2010-15*, August 2008, p. 20.

¹²⁰ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 28; Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 32.

¹²¹ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 28. Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 32.

¹²² AER, *Connection charge guidelines for electricity retail customers*, June 2012.

¹²³ NER, clause 6.2.1(c)(4).

¹²⁴ NER, clause 6.2.1(d).

connections can be attributed to a specific customer, giving further weight to an alternative control classification.¹²⁵

Temporary connections

Distributors provide temporary connections to specific customers on request. Examples of temporary connections include blood bank vans and school fetes. Because only the distributor may provide temporary connections, our proposed approach is to classify these as direct control services.¹²⁶ As they are provided to specific customers, we propose to further classify temporary connections as alternative control services.¹²⁷ Our proposed approach is consistent with the current classification.¹²⁸

Connection management services (post connection)

In addition to the connection services discussed above, Energex and Ergon Energy provide a further range of connection related services. These include services such as moving the point of attachment to the network, auditing connections after energisation or upgrading a connection from an overhead to an underground connection.¹²⁹ We have grouped these services together and named them 'connection management services'. Energex and Ergon Energy provide these services under their distribution authorities. Given this barrier to competition, our proposed approach is to classify this service group as direct control services.¹³⁰ Because the distributors provide these services to specific customers, we further propose to classify them as alternative control services.¹³¹ Our proposed approach is consistent with the current classification for such services.¹³²

Removal of network constraint for embedded generator

Connection management services include network augmentation required to remove a network constraint faced by a generator. Network constraints physically limit a generator's ability to send electricity into the shared network. Generators facing network constraints may ask their distributor to enhance the distribution network in a specific region to allow it to supply more electricity into the broader shared network. While distributors carry out this work on the shared network, it is undertaken to benefit a specific customer—the generator affected by the network constraint.¹³³ We consider it is efficient for the benefitting generator to pay the full cost of a distributor's work to remove a network constraint. Therefore, we set out in our preliminary positions F&A our proposed approach to group this service with other connection related services benefitting specific customers and classify the service group as alternative control.¹³⁴

In response to our preliminary positions F&A, Ergon Energy requested that we clarify this service includes any associated upstream works (broadly, in this context 'upstream works' refers to network augmentation undertaken more remotely from the generator).¹³⁵ Ergon Energy further submitted that measures will be required to ensure embedded generators are not required to fund upstream works that would otherwise be required to benefit the broader network.

¹²⁵ NER, clause 6.2.2(c)(5).

¹²⁶ NEL, s. 2F(a).

¹²⁷ NER, clause 6.2.2(c)(5).

¹²⁸ AER, *Framework and approach paper – classification of services and control mechanisms – Energex and Ergon Energy 2010-15*, August 2008, p. 51.

¹²⁹ See Appendix B for services grouped as 'connection management services'.

¹³⁰ NEL, s. 2F(a).

¹³¹ NER, clause 6.2.2(c)(5).

¹³² AER, *Framework and approach paper – classification of services and control mechanisms – Energex and Ergon Energy 2010-15*, August 2008, p. 51.

¹³³ NEL, s. 2F(a). Also, NER, cl. 6.2.2(c)(5).

¹³⁴ AER, *Preliminary positions paper F&A for Qld*, December 2013, p. 29.

¹³⁵ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 49.

We agree that the distributors should be able to charge embedded generators for upstream works associated with removing a network constraint. However, we are currently unable to see how such an alternative control service would work in practice. We invite the distributors to set out in their connection policies the circumstances in which an embedded generator would be expected to fund the cost of upstream works. We anticipate the distributors will submit connections policies with their regulatory proposals. When reviewing the connections policies in our preliminary determination we may consider that unforeseen circumstances have arisen that justify us altering our classification approach to allow the distributors to charge for upstream works. Our approach to this issue is consistent with our approach to shared network augmentation caused by large customer connections.

Accreditation of alternative service providers and approval of their designs, works and materials

Energex and Ergon Energy undertake a range of services related to alternative service providers for large customer connections. For example, they are currently responsible for the authorisation, or accreditation, of alternative service providers to perform large customer connections for their respective networks. Also, before an alternative service provider performs large customer connection works, the distributors must approve the connection designs. And finally, once a connection has been completed the distributors must assess the works.

Our proposed approach is to group together the services performed by Energex and Ergon Energy in relation to alternative service providers for large customer connections. We further propose to classify them consistently. Only Energex and Ergon Energy may perform these services, so our proposed approach is to apply a direct control classification.¹³⁶ Because the distributors provide these services to specific customers, we further propose to classify them as alternative control services.¹³⁷

We currently classify the accreditation of alternative service providers to perform large customer connections as a standard control service. This means the cost of this service is shared across the broad customer base. We now consider that distributors should bill the alternative service providers for the cost of the accreditation process. We consider this to be consistent with a user pays approach and more efficient than the current approach. By classifying alternative service provider accreditation as an alternative control service, we will facilitate such a change. Together, we consider these factors establish that a different classification is clearly more appropriate than the present classification. Energex and Ergon Energy did not oppose our proposed approach.¹³⁸

1.3.4 Metering services

This section first explains the different metering types and different metering services. In doing so, we summarise the categories of metering services we propose to apply and our proposed classification of the different metering types. Second, we set out our reasons for our proposed approach to the classification of metering services.

¹³⁶ NEL, s. 2F(a).

¹³⁷ NER, clause 6.2.2(c)(5).

¹³⁸ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 54. Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 69.

Introduction to metering services

All electricity customers have a meter that measures the amount of electricity they use.¹³⁹ However, not all customers have the same type of meter. There are different types of meters, measuring electricity usage in different ways. Table 4 below describes each metering type.

Table 4: Metering types

Metering type	Description
Type 1 to 4 meters	Smart meters, generally used by large customers who consume greater than 160 megawatt hours (MWh) of electricity per annum. Have capability to record time of use of energy and are read remotely. Increasingly used by small customers, including residential customers.
Type 5 meters	Manually read interval meters with capability to record time of use of energy.
Type 6 meters	Manually read accumulative meters which simply record total electricity usage. Currently the default meter type for households and other small consumption users.
Non-standard type 6 import and export meters (in South Australia)	Accumulative meters with generally the same functionality as standard type 6 meters but able to differentiate between import and export energy flows. Generally provided to users with small embedded generators (Solar Photovoltaic units) to measure energy exported to the grid.
Type 7 meters	Type 7 meters are unmetered connections. Examples include streetlights or traffic lights. Usage of electricity by type 7 meter connections is estimated using formulae and standard data.

Source: AER

The Qld distributors are the monopoly providers of type 5¹⁴⁰ (interval) and 6 (accumulation) meters.¹⁴¹ Households and other small customers use these meter types. Type 6 meters simply record total electricity usage over a period of time. Type 5 meters can record electricity usage and time of use.¹⁴²

Large customers use type 1 to 3 meters which provide a range of additional functions compared to type 5 and 6 meters. Type 1 to 3 meters are competitively available and we do not regulate them—they are unclassified. Type 4 meters or 'smart meters' are competitively available for purchase from the Qld distributors or alternative providers. These are interval meters with a communications capability allowing distributors or a third party to read them remotely. Small customers are increasingly seeking smart meters because they offer frequent information about usage and facilitate a range of other services.¹⁴³ This allows customers to manage their electricity use better.

The Qld distributors are the monopoly providers of type 7 metering services, which are unmetered connections (for example, public lighting connections).¹⁴⁴ 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.

¹³⁹ All connections to the network must have a metering installation (NER, clause 7.3.1A(a)).

¹⁴⁰ Generally, Energex and Ergon Energy do not provide type 5 meters.

¹⁴¹ The Qld distributors are the 'responsible person' for type 5, 6, and 7 metering installations (NER, clause 7.2.3(a)(2)).

¹⁴² Interval meters record electricity usage every 30 minutes.

¹⁴³ Such as remote load control by distributors and remote appliance control by customers.

¹⁴⁴ NER, clause 7.2.3(a)(2).

Auxiliary metering services are a range of other metering related services provided to specific customers. These include customer-requested meter tests, additional meter reads or equipment alterations.

Type 5 and 6 metering services are currently bundled with other services and classified as standard control services. This means the current classification of metering services applies to meter installation, provision, maintenance, reading and data management.

Customers must pay for metering services, as they do for all other electricity services. At issue is whether the Qld distributors should continue to bundle the cost of type 5 to 7 metering services in basic electricity network charges (classified as standard control services) as they currently do. Alternatively, should Energex and Ergon Energy separate, or unbundle, these charges (classified as alternative control services)? Whether the Qld distributors bundle or unbundle these charges depends on the way we classify metering services.

Table 5 summarises the current classification and our proposed approach to the classification of metering services.

Table 5: AER's current and proposed classification of metering services

Current classification	AER's proposed classification
Metering types 1 to 4 – unclassified	Metering types 1 to 4 – unclassified
Metering types 5 and 6 – standard control	Metering types 5 and 6 - alternative control – This includes installation (including on site connection of a meter at a customer's premises, and on site connection of an upgraded meter at a customer's premises where the upgrade was initiated by the customer), provision, maintenance, reading and data services. Meter provision refers to the capital cost of purchasing the metering equipment to be installed. Meter maintenance covers works to inspect, test, maintain, repair and replace meters. Meter reading refers to quarterly or other regular reading of a meter. Metering data services involve the collection, processing, storage, delivery and management of metering data.
Meter type 7 – standard control	Meter type 7 – standard control
Auxiliary metering services – alternative control	Auxiliary metering services – Alternative control

Source: AER

Type 1 to 4 metering services

Type 1 to 4 metering services are contestable in Qld and competitively available.¹⁴⁵ For this reason, our proposed approach is not to classify these services.¹⁴⁶ Consequently, we will not regulate them. This is consistent with our current regulatory approach in Qld and in other jurisdictions.¹⁴⁷ This is also consistent with our approach set out in our preliminary positions F&A.¹⁴⁸

¹⁴⁵ 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)).

¹⁴⁶ NEL, ss. 2F(a)(d).

¹⁴⁷ 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.

¹⁴⁸ AER, *Preliminary positions paper F&A for Qld*, December 2013, p. 32.

Type 5 and 6 metering services

Energex and Ergon Energy are the monopoly providers of type 5 and 6 meters.¹⁴⁹ Therefore, we propose to retain the current direct control classification for these services.¹⁵⁰

In terms of which direct control classification to apply, our proposed approach is to classify type 5 and 6 metering services as alternative control, changing from the current standard control classification. As standard control services, the costs of type 5 and 6 metering services are currently included in the basic electricity network charges all customers pay. By changing the classification to alternative control, Energex and Ergon Energy would remove these meter charges from their standard network charges and add a separate metering charge to customer bills. To explain why our proposed approach would benefit Qld customers more broadly, we next describe the benefits for an example customer.

Under the current approach, where type 5 and 6 metering services are classified as standard control, suppose a customer switches from a type 5 or 6 meter to a type 4 smart meter. The customer must pay for the new type 4 meter. However, the distributor will still charge that customer for the type 5 and 6 services that are bundled in standard electricity charges even though that customer no longer uses a type 5 or 6 meter. However, if type 5 and 6 metering services were unbundled from standard network charges and billed separately, our example customer with a new type 4 meter would pay only for that new meter and, potentially, an exit fee. The exit fee would recover from the customer any costs of the type 5 or 6 meter the distributor has not yet recovered.

Also, some customers have more than one meter. Additional meters may be for solar power units, for example. Under the current standard control classification, the total cost of type 5 and 6 metering services are averaged and billed across all network customers equally. This means Qld customers with more than one meter are currently subsidised by customers with only one. By unbundling type 5 and 6 metering from standard network charges, distributors may charge customers with more than one meter for the multiple meters they use. In this way, customers with only one meter would no longer subsidise customers with multiple meters.¹⁵¹

Therefore, we consider changing the classification of type 5 and 6 metering services to alternative control would have at least two benefits:

- **Remove a barrier to entry for smart meters**

Customers who choose to buy a smart meter would not have to pay an ongoing charge for a type 5 or 6 meter they no longer use. This would remove a barrier to entry for smart meters, allowing a range of customer and network benefits to be realised.¹⁵² This proposed change in classification is consistent with the Qld Government's policy position to allow a voluntary (or discretionary) roll-out of smart meters.¹⁵³ It is also consistent with recommendations by the Australian Energy Market Commission (AEMC) to facilitate more flexible metering arrangements.¹⁵⁴

¹⁴⁹ NER, clause 7.2.3(a)(2).

¹⁵⁰ NEL, s. 2F(a).

¹⁵¹ NER, clause 6.2.2(c)(5).

¹⁵² NER, clause 6.2.2(c)(1).

¹⁵³ Queensland Government, *Queensland Government response to the interdepartmental committee on electricity sector reform*, June 2013, p. 6.

¹⁵⁴ AEMC, *Power of choice review – giving consumers options in the way they use electricity – final report*, November 2012, chapter 4.

▪ Users pay

Customers with more than one meter would no longer be subsidised by customers with only one. Customers would pay for the metering services they use. Those customers with multiple meters would pay for multiple meters and vice versa.¹⁵⁵

As a consequence of the second benefit listed above, customers with more than one meter will face higher metering charges than they currently pay. Setting specific metering charges equal to actual metering use would be more efficient in terms of cost reflectivity and more equitable.

Overall, we consider that our proposed approach to type 5 and 6 metering services will have non-price benefits for customers. This includes promoting competition and providing customers with more information and greater choice. We discuss this further below. For these reasons, we consider the proposed new approach 'is clearly more appropriate' than existing classification arrangements for these services.¹⁵⁶

We intend to classify type 7 metering services separately. We also discuss this issue in more detail below.

Meter installation services

In our preliminary positions F&A we proposed to separately classify meter installation services.¹⁵⁷ We now consider that separately classifying a service group specifically for meter installation services is unnecessary. We consider that contestability and efficient pricing is not affected by including meter installation in the broader service group for meter provision, maintenance, reading and data services. As such, we now propose to group type 5 and 6 meter installation services with other type 5 and 6 metering services.

Meter installation, provision, maintenance, reading and data services

We propose to classify type 5 and 6 metering installation, provision, maintenance, reading and data services as direct control services and further as alternative control services. We consider it necessary to apply a direct form of regulation for the following reasons:¹⁵⁸

- There is currently a regulatory barrier to any party other than the Qld distributors providing type 5 and 6 metering provision, maintenance, reading and data services.¹⁵⁹ Under the rules, only the relevant distributor may install a type 5 or 6 meter in its distribution service area.¹⁶⁰
- Type 5 and 6 metering services are subject to a direct form of regulation in other NEM jurisdictions.¹⁶¹
- There is competition available from type 4 meters.¹⁶²

We must further classify type 5 and 6 metering services as standard or alternative control services.¹⁶³ We consider these services should be alternative control services because they are provided to

¹⁵⁵ Relevant under NER, clause 6.2.2(c)5

¹⁵⁶ NER, clause 6.2.2(d).

¹⁵⁷ AER, *Preliminary positions paper F&A for Qld*, December 2013, p. 33.

¹⁵⁸ NER, clause 6.2.1.

¹⁵⁹ NEL, s. 2F(a).

¹⁶⁰ NER, clause 7.2.3(a)(2).

¹⁶¹ AER, *Stage 1 Framework and approach paper – Ausgrid, Endeavour Energy and Essential Energy*, March 2013, p. 26.

AER, *Framework and approach paper – Aurora Energy Pty Ltd*, November 2012, p. 25.

¹⁶² NEL, s. 2F(a) and (d).

specific customers¹⁶⁴ and there is potential for contestability in type 5 and 6 metering services in future.¹⁶⁵

We recognise that the Qld distributors are currently the monopoly providers of type 5 and 6 metering services.¹⁶⁶ However, separating the costs of meter installation, provision, maintenance, reading and data services from shared network charges will enhance competition should contestability for these services change.¹⁶⁷ If charges for these services remain bundled in distribution charges, any future changes in contestability may be far less effective.

Another relevant factor we have considered is creating a more transparent and accurate way of providing customers with costing information.¹⁶⁸ Making metering costs transparent under an alternative control classification will allow customers more informed choices on metering installation, provision, maintenance, reading and data services.

Energex and Ergon Energy support our proposed approach to unbundle type 5 and 6 metering services and classify them as alternative control.¹⁶⁹ However, both distributors raised a number of issues for us to take into account when considering our classification approach, including that they will incur administrative costs from our change in classification. We consider such administrative costs will be relatively minor compared to the benefits of an alternative control classification.¹⁷⁰

The Council of the Ageing – Queensland submitted cautious support for our proposal to unbundle type 5 and 6 metering services.¹⁷¹ While it submitted support for facilitating a wider range of metering options and potential suppliers, plus lower costs from competition, it noted concerns about the cost implications for customers with more than one meter. It also noted that a range of electricity reforms are under way, with potential to significantly impact on residential customers. Energy industry participants, Origin¹⁷² and Simply Energy,¹⁷³ supported our proposed approach.

Power of Choice review

As set out above, we propose to unbundle type 5 and 6 metering services from standard network charges, separate them into different categories of metering services and classify each component as alternative control. Our proposed approach is consistent with the AEMC's final report for its Power of Choice Review.¹⁷⁴ The AEMC designed its recommendations to promote the investment in, and use of, advanced metering infrastructure ('smart' metering). It considers there will be demand management benefits for customers, retailers and distributors from the use of smart meters.

¹⁶³ NER, clause 6.2.2(c).

¹⁶⁴ NER, clause 6.2.2(c)(5).

¹⁶⁵ NER, clause 6.2.2(c)(1).

¹⁶⁶ NER, clause 7.4.2(c) establishes that a distributor who is the responsible person for a metering installation must either register with AEMO as a metering provider or engage registered metering providers for such installations.

¹⁶⁷ NER, clauses 6.2.2(c)(1) and (c)(6).

¹⁶⁸ NER, clause 6.2.2(c)(6).

¹⁶⁹ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 22; Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 56.

¹⁷⁰ NER, cl. 6.2.2(c)(2).

¹⁷¹ COTA, *submission to AER*, February 2014, p. 1.

¹⁷² Origin, *Re. Framework and approach for Energex and Ergon for period commencing 1 July 2015*, 13 February 2014, p. 1.

¹⁷³ Simply Energy, *Preliminary positions paper: Framework and approach for Energex and Ergon Energy*, 19 February 2014, p. 1.

¹⁷⁴ AEMC, *Power of choice review – giving consumers options in the way they use electricity – final report*, November 2012, chapter 4.

The AEMC recommended metering costs be unbundled from shared network charges.¹⁷⁵ Also, it recommended that provision of metering services be contestable. While we do not determine the contestability of metering services, our proposed approach to classification would facilitate contestability if legislative changes occur to open up the market. The AEMC has recommended that measures to promote contestability for type 5 and 6 metering be pursued. Moreover, a rule change proposal to provide contestability in this service has now been lodged with the AEMC.¹⁷⁶ Therefore, we are confident that our approach to unbundle type 5 and 6 metering services will complement potential legislative changes to make these services contestable.¹⁷⁷

Based on the analysis above, our proposed approach is that it is clearly more appropriate to classify type 5 and 6 metering services as alternative control. Our proposed approach is consistent with our position set out in the preliminary positions F&A.

Type 7 metering services

A type 7 metering service does not measure the flow of electricity. Rather, a type 7 'metering' service consists of estimating the amount of electricity used by, for example, public lights or traffic lights. Distributors charge customers, usually councils or government agencies, for unmetered connections by estimating the usage using standard data. For example, the distributor estimates public light usage using the total time the lights were on, the number of lights in operation, and the light bulb wattage. As only distributors estimate usage, only they can bill customers.

Energex and Ergon Energy are the monopoly providers of type 7 metering services. This is because, as indicated above, the cost of providing type 7 metering services is nominal.¹⁷⁸ For this reason, an alternative provider has limited incentive to enter the market for the provision of type 7 metering services. The Qld distributors are already performing data management services for type 5 and 6 meters. Providing type 7 metering services is a logical extension for the Qld distributors to undertake.

We consider that there is no potential to develop competition in the provision of type 7 metering services.¹⁷⁹ Therefore, we intend to classify type 7 metering services as direct control services. In terms of our further classification as either standard control or alternative control services, we can see no reason to change from the current classification—standard control. Any costs associated with type 7 metering services are minimal. As such, we consider a different approach to the current classification is not 'clearly more appropriate.'¹⁸⁰ Therefore, our proposed approach is to continue to classify type 7 metering services as standard control services. Our proposed approach is consistent with our position set out in the preliminary positions paper F&A for Qld.

Auxiliary metering services

Energex and Ergon Energy also provide a range of metering related services to customers on request. Examples include customer requested meter tests, additional meter reads or equipment alterations. We propose to group these metering services together as 'auxiliary metering services'.

¹⁷⁵ AEMC, *Power of choice review – giving consumers options in the way they use electricity – final report*, November 2012, p. 83.

¹⁷⁶ AEMC, *Energy Market Reform Working Group - bulletin 20*, September 2013.

¹⁷⁷ NER, cl. 6.2.2 (c)(1).

¹⁷⁸ This is because an equation is used to calculate type 7 metering usage. No physical meter or associated services are necessary.

¹⁷⁹ NEL, s. 2F(a).

¹⁸⁰ NER, clause 6.2.1(d)(1).

We think contestability in auxiliary metering services is limited by the monopoly nature of the provision of type 5 and 6 metering services, to which most auxiliary metering services relate.¹⁸¹ For example, only Energex or Ergon Energy can perform an additional meter read as the monopoly provider of type 5 and 6 meter reading services.¹⁸² For this reason, we propose to classify auxiliary metering services as direct control services.

Having decided to apply a direct control classification, we must further classify auxiliary metering services as either standard control or alternative control. Because Qld distributors provide auxiliary metering services to specific customers, we propose to classify them as alternative control services.¹⁸³

Under our proposed approach, customers using auxiliary metering services will pay for the services they use. To the extent that the provision of auxiliary metering services is contestable, or may become contestable, our proposed approach would facilitate this.

Metering classification summary

On the basis of our above analysis, our proposed approach is to classify metering services as summarised in table 6.

Table 6: AER's proposed approach to classifying metering services

AER's proposed approach	
Service	Proposed classification
Metering type 1 to 4	Unclassified
Type 5 and 6 metering services	Alternative control
Metering type 7	Standard control
Auxiliary metering services	Alternative control

Source: AER

1.3.5 Ancillary network 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'.¹⁸⁴

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 characteristic of being non-routine services provided to individual customers on an 'as needs' basis. Examples include customer requested appointments or after hours service provision. Ancillary network services involve work on, or in relation to, parts of the

¹⁸¹ NEL, s. 2F(a) and (d).

¹⁸² NER, clause 7.2.3(a)(2).

¹⁸³ NER, clause 6.2.2(c)(5).

¹⁸⁴ AER, *Framework and approach paper – classification of services and control mechanisms – Energex and Ergon Energy 2010-15*, August 2008, p. 12.

Qld distributor's distribution network. Therefore, as with network services, only the distributor can perform these services.

We consider that, as with network services, there is a regulatory barrier preventing any party other than Energex or Ergon Energy providing ancillary network services.¹⁸⁵ Because of this monopoly position, customers have limited negotiating power in determining the price and other terms and conditions on which the distributors provide these services. Furthermore, the scale of resources used by the distributors to provide ancillary network services also likely prevents alternative providers from competitively providing them.¹⁸⁶ These factors contribute to our view that, like network services, Energex and Ergon Energy possess significant market power in providing ancillary network services.

Because of these barriers to competition from alternative service providers, we propose to classify ancillary network services as direct control services.¹⁸⁷

Having decided to apply a direct control classification, we must further classify ancillary network services as either standard control or alternative control. We intend to classify ancillary network services as alternative control because they are attributable to individual customers.¹⁸⁸ 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.¹⁸⁹ 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.¹⁹⁰ This results in costs that are more transparent for customers. Additionally, the note to clause 6.2.2(c)(5) of the rules states:

In circumstances where a service is provided to a small number of identifiable consumers on a discretionary or infrequent basis, and costs can be directly attributed to those consumers, it may be more appropriate to classify the service as an alternative control service than as a standard control service.

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

1.3.6 Public lighting

We propose to classify public lighting (including emerging public lighting technology) as a direct control service and further, as alternative control. This is consistent with our current approach.

Energex and Ergon Energy operate and maintain public lighting throughout Qld, as part of their distribution networks. The distributors provide these services on behalf of local councils and State government departments responsible for public lighting. The rules do not define public lighting services. However, we have consistently defined the following public lighting services in other distribution determinations:

- the operation, maintenance, repair and replacement of public lighting assets

¹⁸⁵ NEL, s. 2F(a).

¹⁸⁶ NEL, s. 2F(d).

¹⁸⁷ NEL, s. 2F(a)(d).

¹⁸⁸ NER, clause 6.2.2(c)(5).

¹⁸⁹ NER, clause 6.2.2(c)(2).

¹⁹⁰ NER, clause 6.2.2(c)(5).

- the alteration and relocation of public lighting assets, and
- the provision of new public lighting.¹⁹¹

We also propose to include emerging public lighting technology (emerging technology) as part of the public lighting services group. As a distribution service, public lighting assets may be upgraded from time to time, just as any other network asset may be upgraded for better service delivery or improved efficiency. In the case of public lighting, evolving technology is producing new luminaires using less electricity than older assets. Emerging technology relates to luminaires that the Qld distributors do not provide, or may not exist, at the time of our distribution determination. Such emerging technology may become available during the next regulatory control period.

While Energex and Ergon Energy do not have a legislative monopoly over these services, a monopoly position exists to some extent.¹⁹² This is because the Qld distributors own the majority of public lighting assets.¹⁹³ That is, other parties would need access to poles and easements for instance to hang their own public lighting assets. However, Energex and Ergon Energy own and control this supporting infrastructure. Therefore, similar to network services, ownership of network assets restricts the operation, maintenance, alteration or relocation of public lighting services to Energex and Ergon Energy.¹⁹⁴ Based on the above analysis, our proposed approach is to classify public lighting services, including emerging technology, as direct control services.¹⁹⁵ This is consistent with public lighting's current classification.

In our preliminary positions F&A we noted that there was potential to classify Energex's public lighting as a negotiated service. This proposal received little to no support from customers and other stakeholders.

As direct control services, we must further classify public lighting services as either standard control or alternative control services.¹⁹⁶ Our proposed approach is to classify public lighting as an alternative control service, also consistent with its current classification. This approach provides scope for third parties and new entrants to provide public lighting services for new public lighting assets. Hence, it may encourage other potential service providers to enter the market in future.¹⁹⁷ There would be no material effect on administrative costs to us, Qld distributors, users or potential users, because we are retaining the current classification.¹⁹⁸ Energex and Ergon Energy can directly attribute the costs of providing public lighting services to a specific set of customers, such as local government councils.¹⁹⁹

1.3.7 Additional classification issues

Energex and Ergon Energy requested that we address a range of other service classification issues.²⁰⁰ In this section we address each of these issues.

¹⁹¹ AER, *Framework and approach paper for Victorian electricity distribution regulation – CitiPower, Powercor, Jemena, SP AusNet and United Energy for regulatory control period commencing 1 January 2010 (final)*, May 2009, pp. 25–26; AER, *Preliminary positions, Framework and approach paper for Aurora Energy Pty Ltd for regulatory control period commencing 1 July 2012*, June 2010, p. 33.

¹⁹² NEL, s. 2F(d).

¹⁹³ NEL, s. 2F(a).

¹⁹⁴ NEL, s. 2F(a)(d).

¹⁹⁵ NER, clause 6.2.1.

¹⁹⁶ NER, clause 6.2.2(c).

¹⁹⁷ NER, clause 6.2.2(c)(1).

¹⁹⁸ NER, clause 6.2.2(c)(2).

¹⁹⁹ NER, clause 6.2.2(c)(3) and (5).

²⁰⁰ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 32.

High load escorts

High load escorts involve services associated with lifting power lines along transport routes to enable high load vehicles to pass and planning appropriate routes for such vehicles. We currently do not classify high load escort services provided by Energex. We accept that this is a distribution service, but that there is a competitive market for these services in Energex's distribution area.²⁰¹ As such, we see no reason to change our classification approach.²⁰² We received no requests to change our classification approach in respect of Energex's high load escort service.

For Ergon Energy, we currently classify the line lifting component of high load escorts as an alternative control service.²⁰³ Ergon Energy requested that we change our classification approach to not classify the line lifting component of its high load escort service.²⁰⁴ We consider a key issue is the degree to which there is competition available.²⁰⁵

At the last reset, Ergon Energy submitted that it had accredited one alternative provider of high load services in its distribution area.²⁰⁶ Also, that it had a standard process to accredit more providers should it receive applications. In our last distribution determination we said our decision to classify Ergon Energy's high load services as alternative control was to allow competition to develop.²⁰⁷ Further, that if a competitive market can be sufficiently demonstrated then we would consider not classifying the service in future.

Subsequent to its submission on our preliminary positions F&A Ergon Energy submitted that it has now accredited three alternative providers of high load escort services.²⁰⁸ Ergon Energy also submitted details of its process for accrediting further service providers. On the basis of this information, we consider a competitive market in Ergon Energy's distribution area is now sufficiently established for us to not classify this service.²⁰⁹ We have also given weight to the desirability for consistency in our classification approach across the Qld distributors.²¹⁰ By not classifying Ergon Energy's line lifting service, we will take a consistent classification approach to Ergon Energy and Energex. For these reasons, we propose not to classify Ergon Energy's line lifting component of its high load escort service.

Instrument transformers for metering purposes

Current and voltage transformers, collectively referred to as instrument transformers, help to safely measure variable electrical loads. We intend to classify services related to instrument transformers as alternative control. In our preliminary positions F&A we listed the provision of instrument transformers within the auxiliary metering services group. Energex proposed that we broaden the service description, to include the installation, testing and maintenance of instrument transformers for

²⁰¹ NEL, s. 2F(d).

²⁰² NER, clause 6.2.1(d)(1).

²⁰³ Currently we do not classify the route scoping component of high load escorts provided by Ergon Energy, consistent with our approach to Energex.

²⁰⁴ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 32.

²⁰⁵ NEL, s. 2F.

²⁰⁶ AER, *Framework and approach paper – classification or services and control mechanisms Energex and Ergon Energy 2012–15*, August 2008, p. 26.

²⁰⁷ AER, *Framework and approach paper – classification or services and control mechanisms Energex and Ergon Energy 2012–15*, August 2008, p. 26.

²⁰⁸ Ergon Energy email, 8 April 2014.

²⁰⁹ NEL, s. 2F(a)(d).

²¹⁰ NER, clause 6.2.1(c)(3).

metering purposes.²¹¹ We agree this proposed change better reflects our intended classification. We have amended the classification table provided at appendix B, consistent with Energex's proposal.

Wasted attendance (truck visit)

Ergon Energy requested that we clarify whether it may recover the cost of a wasted attendance, or wasted truck visit.²¹² That is, when the distributors dispatch staff to perform a service but the customer does not facilitate its performance by, for example, not allowing access to the premises. Currently, wasted attendance is separately classified as an alternative control service.

Our classifications table in our preliminary positions F&A listed 'attendance at customer's premises to perform a statutory right where access is prevented'.²¹³ We consider this provides the distributors with the ability to charge for a wasted attendance in a range of circumstances. Ergon Energy submitted that this does not adequately cover all circumstances in which it may incur costs for a wasted attendance. Notwithstanding our inclusion of this service in our classifications table, we consider wasted attendance to be an element of a service provided by the distributors. That is, it is not a service in itself. We further consider the cost of a wasted attendance should be recovered consistently with the classification of the related service.

In the context of an alternative control service, we consider the distributors are able to charge customers for a wasted truck visit under our classification of the related alternative control service. For example, a wasted truck visit in relation to a special meter read may be charged to the customer to whom the special meter read service is provided.

Afterhours services

In our preliminary positions F&A we set out an 'afterhours' service for de-energisation and re-energisation. Ergon Energy requested that we explicitly set out in our classifications table afterhours services for other services, though it did not specify which.²¹⁴ We consider this is not necessary for Ergon Energy (and Energex) to set different fees for afterhours provision of alternative control services. Our inclusion of afterhours services for de-energisation and re-energisation in our preliminary positions F&A should not be taken as excluding afterhours fees in other circumstances. We consider afterhours provision of a service is simply a component, or a variant, of a service. It is not a service in itself. We consider the distributors are able to charge afterhours rates for alternative control services under our classification of the related service.

Priority services

Ergon Energy requested that we establish a new service for the priority provision of a service that is provided within standard hours.²¹⁵ For example, to energise premises on the day the request is made. We consider Ergon Energy (and Energex) is unlikely to incur additional costs from performing a service within standard hours. Therefore, charging a premium for performing such a service is unlikely to reflect the efficient cost. We do not agree with Ergon Energy's request.

²¹¹ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 25.

²¹² Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 34.

²¹³ AER, *Preliminary positions paper F&A for Qld*, December 2013, p. 97.

²¹⁴ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 34.

²¹⁵ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 34.

Distribution services provided in unregulated isolated supply networks

Ergon Energy requested that we list unregulated isolated supply networks as an unregulated service in our classifications table.²¹⁶ We have added this service to our classifications table at appendix B.

Services associated with embedded generation installed within customer's premises

Ergon Energy requested that we add additional services related to customers installing embedded generators.²¹⁷ Specifically, Ergon Energy asked us to add 'witness testing' and the 'assessment of parallel generation applications'. Also, that our classifications be 'flexible' to account for potential service reforms by the Qld Government. In this section we deal with each of these issues.

Witness testing is the testing of assets on the customer's side of an embedded generator connection to ensure they meet the relevant technical standards. Ergon Energy proposed this service be classified as alternative control, because related costs can be attributed to a specific customer. We agree that this is a distribution service, that it is subject to a distributor's monopoly power and related costs can be attributed to an identifiable customer. Therefore, we have added witness testing to the service group 'other recoverable works', which we propose to classify as alternative control.

Assessment of parallel generator applications relate to generators that customers install but that do not export electricity to the network. The distributors are required to assess these generators. This service was included in the classifications table in our preliminary positions F&A. Therefore, we consider we have already addressed Ergon Energy's request that the service be established and classified as alternative control.

In respect of Ergon Energy's request that our service classifications be flexible, we do not agree with Ergon Energy's proposal. We consider the rules require our classification decisions to be clear. Should new services be introduced, we consider the rules further require us to consider those services in order to classify them appropriately. We do not agree with Ergon Energy's request.

Aerial markers and provision of network data

Ergon Energy requested that we establish a new service, 'aerial markers', as an alternative control service.²¹⁸ This service was included in the classifications table in our preliminary positions F&A. Therefore, we consider we have already addressed Ergon Energy's request.

Similarly, Ergon Energy requested that we establish a new service related to the provision of network data to customers on request. Again, the classifications table in our preliminary positions F&A included this service, under 'other recoverable works'.

1.4 AER's service classification approach

In summary, we intend to group and classify Energex's and Ergon Energy's distribution services as set out in table 7. Appendix B sets out a list of the Qld distributors' distribution services and our proposed classifications.

²¹⁶ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 34.

²¹⁷ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 35.

²¹⁸ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 35.

Table 7: Proposed distribution service classifications – summary

AER service group	Proposed classification of distribution services	Proposed classification of direct control services
Network services (excluding emergency recoverable works that are unclassified)	Direct control	Standard control
Connection services		
Small customer connections	Direct control	Standard control
Large customer connections	Direct control	Alternative control
Real estate development connections	Direct control	Alternative control
Commissioning and energisation of large customer connections	Direct control	Alternative control
Pre-connection services—general information provision	Direct control	Standard control
Pre-connection services—requested by customers	Direct control	Alternative control
Temporary connections	Direct control	Alternative control
Connection management services (post connection)	Direct control	Alternative control
Metering services		
Types 1 to 4	Unclassified	
Types 5 to 6	Direct control	Alternative control
Type 7	Direct control	Standard control
Auxiliary metering services	Direct control	Alternative control
Ancillary network services	Direct control	Alternative control
Public lighting services	Direct control	Alternative control

Source: AER

2 Control mechanisms

This attachment sets out our decision, together with our reasons, on form of control mechanisms to apply to the Qld distributors' direct control services for the 2015–20 regulatory control period. This attachment also sets out our proposed approach on 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 provides our proposed classification of Qld 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.

The form of control mechanisms must be as set out in our F&A paper.²¹⁹ Additionally, the formulae that give effect to the control mechanisms in a distributor's regulatory proposal must be the same as the formulae set out in our F&A paper, unless we consider that unforeseen circumstances justify departing from the formulae set out in that paper.²²⁰

2.1 AER's decision

We have decided to apply the following forms of control in the 2015–20 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 and a fee can be set at the determination.

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 mechanisms²²¹
- the formulae to give effect to the control mechanisms
- the basis of the control mechanism²²²

The rules set out the control mechanisms that may apply to both standard and alternative control services.²²³

²¹⁹ NER, clause 6.12.3(c).

²²⁰ NER, clause 6.12.3(c1).

²²¹ NER, clause 6.2.5(b).

²²² NER, clause 6.2.6(a).

²²³ NER, clause 6.2.5(b).

- 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. Distributors comply 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 services²²⁴

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 total revenue allowed for each year of the regulatory control period. Distributors must then recover revenue equal to or less than the total revenue. Distributors comply 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 total revenue. 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 total revenue in future years. This operation occurs through an 'overs and unders' account, whereby any over-recovery (under-recovery) is deducted from (added to) the total revenue 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. Distributors comply 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 total revenue by a particular unit (or units) of output, usually kilowatt hours (kWh). The distributor complies with the constraint by setting prices so the average revenue is equal to or less than the total revenue 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.

²²⁴ 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.

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 distributors to manage distribution use of service charges shared across the broad customer base. Consequently, our assessment approach is focussed on a revenue cap or WAPC.

2.2.1 Standard control services

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

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

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

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

The basis of the control mechanism for standard control services must be of the prospective CPI-X form or some incentive-based variant.²²⁵

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

Need for efficient tariff structures

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

Efficient pricing is important for several reasons:

- Where prices are cost reflective, allocative efficiency is maximised because consumers can compare the cost of providing the service to their needs and wants.²²⁶

²²⁵ NER, clause 6.2.6(a).

²²⁶ 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.

- 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.
- Cost reflective prices allow distributors to 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, distributors 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 generally desirable.

Revenue recovery

We consider that a control mechanism should give distributors 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 distributors recover additional revenue from price sensitive services through prices above marginal cost.

Pricing flexibility and stability

Price flexibility enables distributors to restructure existing prices and/or introduce charges for new services.

The stability and predictability of distribution network prices is important because it affects consumers' ability to manage bills and retailers' ability to manage risks incurred from changes to network prices.

Incentives for demand side management

Demand side management refers to the implementation of non-network solutions to avoid the need to build network infrastructure to meet increases in annual or peak demand.²²⁷

2.2.2 Alternative control services

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

- the potential for competition to develop in the relevant market and how the control mechanism might influence that potential

²²⁷ Generally peak demand is referred to as the maximum load on a section of the network over a very short time period.

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

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

We must state what the basis of the control mechanism is in our distribution determination.²²⁸ 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.

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

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 better alignment with the introduction 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. 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, for the majority of distributors the costs of supply are fixed or relate to peak demand, so efficient prices will be structured around fixed or peak prices.²²⁹ Second, because customers' willingness to pay for connection to the network is generally higher than for electricity consumption, the largest margin (above the cost of supply) is likely to be applied to fixed (connection) prices.

We note that similar to other jurisdictions (regardless of control mechanism) Qld distributors recover significant revenue from flat energy tariffs which are unrelated to the peak periods of demand by time or location.

²²⁸ NER, clause 6.2.6(b).

²²⁹ Peak prices include peak energy, demand and capacity prices.

We consider that by itself the revenue cap provides limited incentive for distributors to set efficient prices. That is, under a revenue cap, distributors' revenues are fixed over the regulatory control period. Distributors therefore maximise profits by decreasing costs. To maximise profits, distributors face an incentive to increase prices above marginal costs on price sensitive services, thereby reducing demand for those services.

We consider that this incentive is unlikely to give rise to inefficient pricing for Qld distributors. We consider that the majority of distributors' variable costs are caused by augmentations and connections (where demand for connections is likely to be price insensitive) to the network. The incentive for distributors to decrease costs through pricing is therefore likely to result in higher prices for peak demand. This would require a shift towards peak energy/capacity. In the current environment where tariffs largely consist of flat energy/capacity tariffs we consider that a shift towards peak energy/capacity prices will result in increases in pricing efficiency.²³⁰

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 from a revenue cap 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 risk to distributors. This would likely lead to increased costs through risk minimisation strategies. Furthermore, the continuation of the revenue cap in Queensland will likely lead to reduced administrative costs to users and us due to consistency across regulatory arrangements. The introduction of a revenue cap in South Australia/New South Wales will be under a revenue cap in 2014–19. Tasmania is already operating under a revenue cap. This consistency will reduce 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 arrangements for relevant services is generally desirable. We consider that this factor needs to be weighed against the other factors under clause 6.2.5(c) of the rules. We consider this is appropriate because consistency in and of itself has no direct effect on distributors, us or customers.

2.3.4 Desirability of consistency between regulatory arrangements

We consider that consistency between regulatory arrangements is generally desirable but is not primary to our considerations in this instance. Consistent regulatory arrangements need to be weighed against the other factors under clause 6.2.5(c) of the rules. Pursuing the other factors produces outcomes that better achieve the national electricity objective and are consistent with the revenue and pricing principles.

2.3.5 Revenue recovery

We consider that a revenue cap provides a high likelihood of efficient cost recovery. We consider that because costs for distributors are largely fixed and unrelated to energy sales, revenue recovery should also be largely fixed and unrelated to energy sales. We note that differences from forecast peak demand and customer numbers may cause differences in distributor costs. Where this occurs, variations from efficient cost recovery may result under the revenue cap. We have therefore

²³⁰ AER, *Stage 1 NSW framework and approach Ausgrid, Endeavour Energy and Essential Energy*, 1 July 2014–30 June 2019, March 2013, p. 48.

considered adjustment mechanisms (hybrid control mechanisms) to the revenue cap for variations from forecast peak demand and customer numbers. Section 1.3.8 outlines our consideration of hybrid control mechanisms.

We consider that a WAPC does not provide a high or even reasonable likelihood of efficient cost recovery. We consider the WAPC provides an opportunity for distributors to recover revenue systematically above forecast. That is, under a WAPC distributors have the opportunity to recover revenue substantially above forecast revenue when actual quantities exceed forecast quantities, and to recover revenue close to forecast when actual quantities are below forecast quantities. We adopted a similar position and reasoning in New South Wales.²³¹

2.3.6 Pricing flexibility and stability

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 distributors are 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. Conversely, under a WAPC, distributors submit reasonable estimates when introducing new tariffs or tariff structures. Given that substantial revenue is at risk, we assess these estimates rigorously which can result in significant changes in profit for distributors. We consider that this is likely to be of increasing importance under changes to the pricing principles proposed by SCER.²³²

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.²³³

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. However, when the account exceeds certain limits (tolerance limits), the adjustment may be made over two or more years. We consider that tolerance limits and the design of the unders and overs account can limit price adjustments in any one year. For example, in Queensland in the current period, we applied tolerance limits to the unders and overs account. In Tasmania,²³⁴ we designed the unders and overs account as a rolling account with an estimate year to help smooth the price adjustments year on year.²³⁵ We also

²³¹ AER, *Stage 1 Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, 1 July 2014–30 June 2019*, March 2013, pp. 48–49.

²³² SCER, *Distribution network pricing arrangements*, 14 November 2013.

²³³ NER, clause 6.18. These include cost pass throughs, jurisdictional scheme obligations, tribunal decisions and transmission prices passed on to the distributors from Transmission Network Service Providers.

²³⁴ AER, *Final distribution determination, Aurora Energy Pty Ltd, 2012–13 to 2016–17, attachments*, April 2012, pp. 2–24.

²³⁵ AER, *Final Distribution Determination Aurora Energy Pty Ltd 2012–13 to 2016–17*, April 2012, pp. 20–23.

This approach means that instead of waiting two years before incorporating the under or over recovery into prices, an estimate (based on nine months of data) used in the calculation of the under or over recovery. This will reduce the

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.²³⁶

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 distributors face 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 also consider that the WAPC can result in greater price instability across regulatory control periods compared to the revenue cap. This is particularly prominent 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 would mean that prices would rise gradually over the regulatory period (rather than jump up at the end of the period).

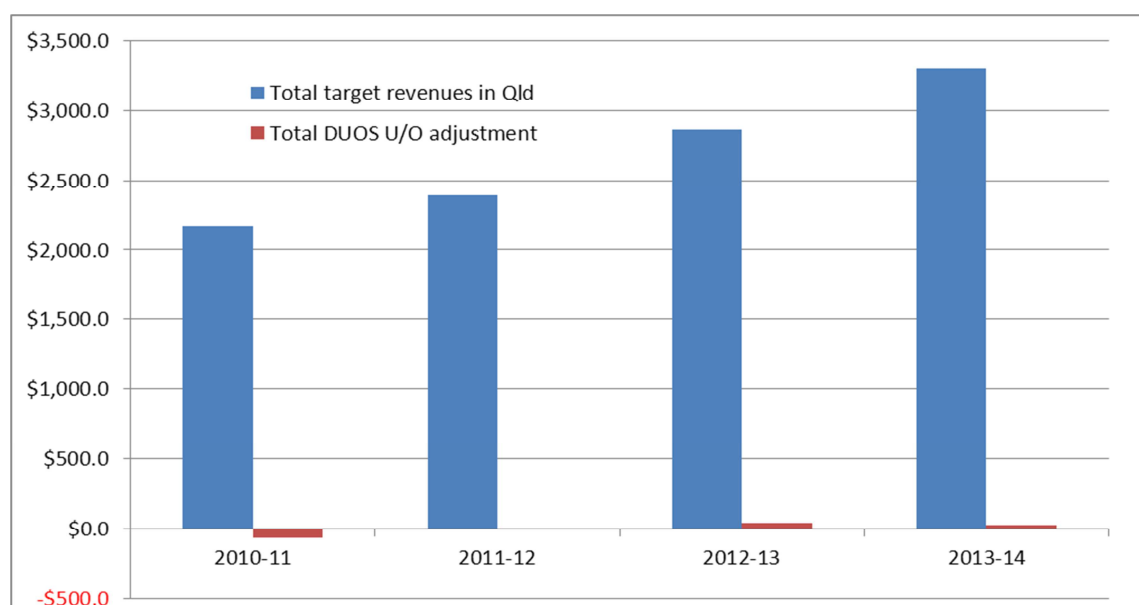
Qld electricity prices have risen sharply in recent years. For this reason, we consider that the main concern of customers is likely to be price volatility rather than changes to a distributor's revenue requirements. As the control formula for standard control services for the current regulatory period is a revenue cap, customers may question whether the revenue cap has contributed to these sharp increases. The following explains the effect of a revenue cap on prices.

A revenue cap limits the amount of revenue a distributor may raise through prices to meet its expected costs. Where prices are set too high or too low, change in prices is required in a subsequent year to ensure the revenue is capped. This correction can only be determined after the year in question. While the annual revenue cap has been increasing in recent years, the subsequent adjustment has remained relatively small. These small overs and unders adjustments to the distribution use of service (DUOS) revenue requirements are shown in Figure 5. They have remained stable throughout the current regulatory control period.

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.

²³⁶ 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.

Figure 5: DUOS unders and overs adjustments for Queensland (\$ millions)



Source: AER

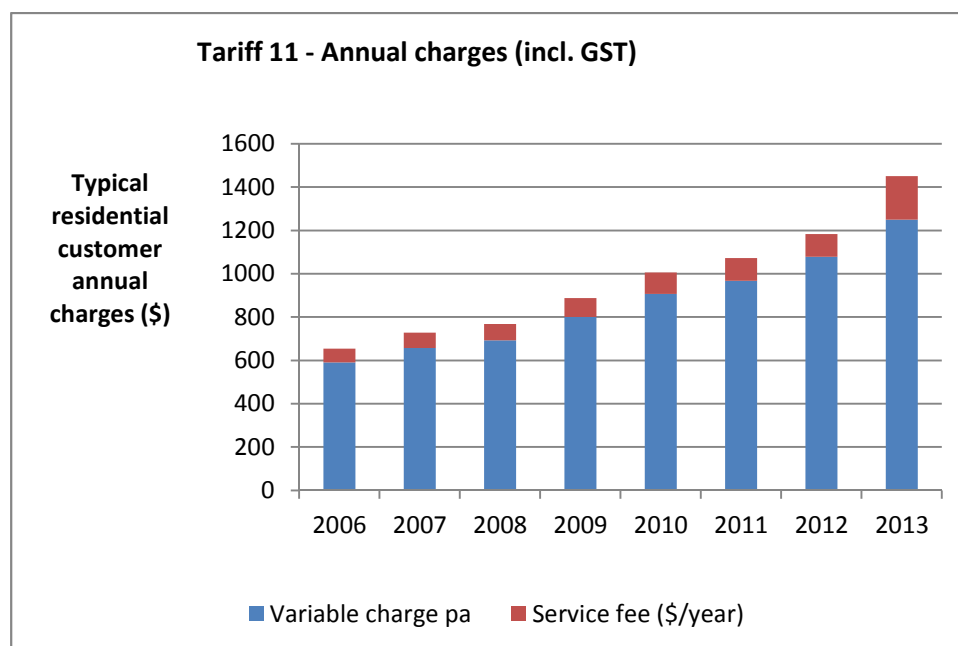
While the annual under and over adjustments have been insignificant, it is quite clear that retail electricity charges have not been stable. Factors that have contributed to steep increases in electricity prices, include:

- substantial increases in network investment that have resulted in real increases in distribution prices each year since the last determination was made. This expenditure (approved by us) was made by Qld distributors to improve service reliability, replace aging assets and cope with peak load caused by rising air conditioner use amongst other things.
- adjustments made by the Australian Competition Tribunal²³⁷ to our final decision for the Queensland Distribution Determination 2010–11 to 2014–15. This amounted to a change in revenue requirements in 2013–14 of 9 per cent for Energex and 7 per cent for Ergon Energy.
- adjustments to incorporate feed-in tariffs that are set by the Queensland Government and which are expected to more than double in 2014–15.

Figure 6 shows how variable and fixed electricity charges have changed for a typical residential customer since 2006. What can be seen in this figure is that while charges have risen significantly, the increases have been reasonably stable. That is, the revenue cap form of control is not causing instability. Rather, where prices have varied from year to year, this has been driven by factors like Queensland Government retail pricing policies and not the revenue cap used to control distribution prices. An example of this includes the increase in the fixed 'service charge' in 2013.

²³⁷ Australian Competition Tribunal, [2011] ACompT 1, 2, 3, 4, 7 and 9.

Figure 6: Typical residential customer electricity charges



Source: AER. The graph is based on annual consumption of 4250 kWh and is inclusive of GST.

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 distributors have the opportunity to recover revenue substantially above forecast revenue when actual quantities exceed forecast 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.

Simply Energy acknowledged that a WAPC can result in volatility in individual tariffs and individual tariff structures.²³⁸ With the inclusion of tolerance limits that smooth unders and overs over a number of years, Simply Energy indicated its support for our approach.²³⁹

2.3.7 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 distributors' revenue over the regulatory control period. Distributors can therefore increase profits by reducing costs. This creates an incentive for distributors to undertake demand side management projects that reduce total costs. That is, any demand side management project where the reduction in network expenditure is greater than the cost of implementing the demand side management. We consider this provides an efficient incentive to distributors to undertake demand side management within a regulatory control period.

²³⁸ Simply Energy, *Preliminary positions paper: framework and approach for Energex and Ergon Energy*, 19 February 2014, p. 2.

²³⁹ Simply Energy, *Preliminary positions paper: framework and approach for Energex and Ergon Energy*, 19 February 2014, p. 2.

Under a WAPC a distributor's profits are linked directly to the actual volumes of electricity distributed. This is because, in practice, distributors have chosen energy based network tariffs in most instances. 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.

2.3.8 Hybrid form of control

We consider that higher administrative costs to distributors and us under a hybrid revenue cap outweigh its potential benefits.

There are a number of different ways to design a hybrid form of control mechanism. We have considered a hybrid revenue cap where revenue is adjusted within the regulatory period to adjust for deviations from forecast cost drivers. That is, customer numbers and peak demand. This design enables distributors' revenues to align more closely to the cost drivers compared with a revenue cap. However, it may be difficult to develop an effective revenue function under a hybrid revenue cap. Under the hybrid revenue cap we must recalculate the distributors' maximum allowable revenue each year. This would involve substantial administrative costs to distributors and us throughout the regulatory control period. Additionally, because a large proportion of distributors' costs are fixed rather than variable such adjustments may only result in small adjustments to distributors' maximum allowable revenues. 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.²⁴⁰ Other regulators (Queensland Competition Authority and the Office of the Tasmanian Economic Regulator) also noted the difficulties and complexities involved in developing and applying a hybrid revenue cap.²⁴¹

In their submissions, Origin and Canegrowers did not support a revenue cap and submitted that a hybrid control mechanism should instead be adopted.²⁴²

Origin submitted that a revenue cap provides little incentive for a distributor to restrain its spending programme when growth in cost drivers such as peak demand and customer numbers fall short of forecast levels. Origin submitted that this can lead to successive price hikes because revenue is currently recovered primarily via volumetric tariff components (even though their costs are largely fixed) and volumes are falling. For these reasons, Origin's first preference is for us to adopt a WAPC. However Origin acknowledged our arguments against a WAPC and in the alternative submitted a revenue cap including a hybrid component where:

- the revenue cap could be adjusted within period in line with changes to key cost drivers such as customer numbers and peak demand when these fall below forecast levels, and
- increasing the fixed component in network prices relative to volumetric components.²⁴³

Origin submitted that together, these hybrid components would help to limit the extent to which network prices must rise in order to allow distributors to recover fixed revenues as volumes fall.²⁴⁴

²⁴⁰ IPART, *Form of Economic Regulation for NSW Electricity Network Charges: Discussion Paper 48*, August 2001, p. 10.
²⁴¹ 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.
²⁴² Origin, *Framework and approach for Energex and Ergon for period commencing 1 July 2015*, 13 February 2014, p.2; Canegrowers, *AER framework and approach: Energex and Ergon Energy*, 24 February 2014, pp. 5–6.
²⁴³ Origin, *Framework and approach for Energex and Ergon for period commencing 1 July 2015*, 13 February 2014, p.2.
²⁴⁴ Origin, *Framework and approach for Energex and Ergon for period commencing 1 July 2015*, 13 February 2014, p.2.

Canegrowers submitted that a hybrid form of control could include a proportion of controlled revenue to provide income certainty to the distributors with a set of price cap constraints to remove within period pricing instability that occurs under a revenue cap.²⁴⁵ Further, Canegrowers submitted that a set of price caps (by using a tariff basket price control or some other method) could be used to limit network price increases to possibly CPI-X. The use of price caps in this way would remove the within period price volatility experienced in the current regulatory control period under a revenue cap.²⁴⁶

There are some similarities in Origin and Canegrowers' submissions as both relate to declining consumption and, if this pattern continues, they contend that a revenue cap would result in steady increases in electricity prices.²⁴⁷

Both submissions were concerned that in the context of declining consumption, a revenue cap would result in steady increases in electricity prices.²⁴⁸ We acknowledge these views but consider that very few of the building block costs calculated at the time of our determination are linked to electricity consumption levels. Many of the building block elements are fixed or vary only slightly over the regulatory control period. Given this, we consider that the form of control alone is not sufficient to deal with the consequences of falling consumer demand on electricity prices. We acknowledge that this is an important issue but we consider it will be better addressed through critically reviewing future capital expenditure during the reset that will form fixed costs to be recovered in future prices.

2.3.9 Formulae for control mechanism

We are required to set out our proposed approach to the formulae that give effect to the control mechanisms for standard control services in the F&A paper.²⁴⁹ We must include the formulae in our final F&A in our distribution determination, unless we consider that unforeseen circumstances justify departing from the formulae as set out in the F&A.²⁵⁰

Below is a proposed formula to apply to standard control services. We consider that the formula gives effect to the revenue cap.

Revenue cap for standard control services (as determined by the post-tax revenue model)

$$(1) AR_t = AR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t)$$

Total allowed revenue (including adjustments for incentive payments and pass throughs etc.)

$$(2) TR_t = AR_t + I_t + B_t + C_t$$

The revenue cap requires that revenue in year t should be no greater than the sum of each price in year t multiplied by each quantity in year t. However, prices must be set in advance and we do not know at the relevant time what the quantities will be. Therefore, a forecast must be used. The difference between forecast and actual revenues will be added to the unders and overs account when it becomes known. We will decide on the forecasts of quantities as part of our annual compliance check taking into account the distributors' proposals.

²⁴⁵ Canegrowers, *AER framework and approach: Energex and Ergon Energy*, 24 February 2014, pp. 5–6.

²⁴⁶ Canegrowers, *AER framework and approach: Energex and Ergon Energy*, 24 February 2014, pp. 5–6.

²⁴⁷ Origin, *Framework and approach for Energex and Ergon for period commencing 1 July 2015*, 13 February 2014, p.2; Canegrowers, *AER framework and approach: Energex and Ergon Energy*, 24 February 2014, pp. 5–6.

²⁴⁸ Origin, *Framework and approach for Energex and Ergon for period commencing 1 July 2015*, 13 February 2014, p.2; Canegrowers, *AER framework and approach: Energex and Ergon Energy*, 24 February 2014, pp. 5–6.

²⁴⁹ NER, clause 6.8.1(b)(2)(ii).

²⁵⁰ NER, clause 6.12.3(c1).

The distributors are to demonstrate compliance with formulae (1) and (2) via the following expression in their initial and annual pricing proposals:

$$TR_t = \sum_{i=1}^n \sum_{j=1}^m p_{ij}^t q_{ij}^t \quad i = 1, \dots, n \text{ and } j = 1, \dots, m \text{ and } t = 1, \dots, 5$$

NOTE: in the event that a jurisdictional scheme/s is introduced then the revenue required for that scheme/s will be in addition to that specified in formula (2).

Where:

AR_t is the allowed revenue for regulatory year t. For the first year of the next regulatory control period, this amount will be equal to the smoothed revenue requirement for 2015–16 set out in the PTRM approved by us. The subsequent year's allowed revenue is determined by adjusting the previous year's allowed revenue for CPI and the X factor.

ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from December in year t–2 to December in year t–1. For example, for the 2015–16 year, t–2 is December 2013 and t–1 is December 2014 and in the 2016–17 year, t–2 is December 2014 and t–1 is December 2015 and so on.

X_t is the X factor for each year of the next regulatory control period as determined in the post-tax revenue model. Likely to also incorporate an annual adjustment for the return on debt. To be decided upon in the final decision.

TR_t is the total revenue allowable in year t.

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

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

C_t is the sum of adjustments likely to incorporate but not limited to pass through events and feed-in tariff payments that are not made under jurisdictional schemes. To be decided upon in the final decision.

p_{ij} 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.

Since our preliminary position paper, we have added an adjustment to our formula. The distributors submitted that the formula must address a range of transitional arrangements. For example, the treatment of solar feed-in tariffs, capital contributions in calculating the annual revenue requirement and revenue adjustments to carry forward any over or under recovered revenue.²⁵¹ Additionally, the formula should provide flexibility to allow for adjustments following changes in the next regulatory control period like the introduction of jurisdictional schemes.

²⁵¹ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 41; Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, pp. 7–8.

Energex submitted that the current control mechanism formulae for direct control services needs to take into account the new return on debt provisions of the rules.²⁵² While a return on debt adjustment will be required to satisfy the rules, we are still undecided how the precise nature of this adjustment will be made. It may impact on one or more parameters of the formulae.

Energex also submitted that it currently faces uncompensated risk on the debt component of its return on debt allowance. Energex submitted that this arises because of a mismatch between the compensation for inflation in the control mechanism and its actual debt raising practices—which involves the issuance of nominal bonds and coupon indexed CPI swaps.²⁵³ The rate of return is to be commensurate with the efficient financing costs of a benchmark efficient entity, rather than the actual financing costs of a particular distributor, such as Energex.²⁵⁴ Accordingly, we considered that the control mechanism—in so far as it relates to the rate of return—should also be determined on the basis of a benchmark efficient entity, rather than Energex's specific circumstances. Energex has not demonstrated that a benchmark efficient entity would be undercompensated for the inflation component of the return on debt. At this stage, we do not see any reason to consider that a benchmark efficient entity would face such under compensation. Accordingly, we have not made an adjustment to the control mechanism in relation to the issue raised by Energex.

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

We will apply caps on the prices of individual services in the next regulatory control period to all alternative control service. Our approach is supported by the Qld distributors.²⁵⁵ We have classified the following services as alternative control services:

- type 5 and 6 metering services
- ancillary network services
- public lighting
- large customer connections.

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

Through the distribution determination process, we will confirm the basis of the control mechanism for alternative control services.²⁵⁶ That is, we will confirm whether we will set prices using a building block approach or another method. Prices for certain ancillary network services will be determined on a quoted basis. The Qld distributors will propose the approach to determining quoted prices, which we will consider in making our distribution determination. Typically, prices for quoted services are based

²⁵² Specifically, NER, clause 6.5.2. Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 41

²⁵³ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 41.

²⁵⁴ NER, clause 6.5.2(b).

²⁵⁵ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 39; Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 9.

²⁵⁶ 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.

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 distributors may only be able to quote on the service once they know 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 ancillary network services, large customer connections and public lighting services because we are continuing with caps on prices of individual services.

We consider the classification of services and the basis of the form of control mechanism are the primary influences on administrative costs. We recognise the proposed change in classification of type 5 and 6 metering services and thus, a change in control mechanism, may result in some additional administrative costs. We consider these costs will largely be incurred in the transitioning to the new control mechanism. We consider the changes will create greater cost reflectivity for these service charges to customers in a user-pays environment. We consider these benefits warrant a short term increase in administrative costs.

2.4.3 Existing regulatory arrangements

We consider consistency across regulatory control periods is generally desirable. Our consideration of other factors in clause 6.2.5(d) of the rules leads us to the conclusion that the continuation of the current control formula of a cap on the price of individual services would lead to an overall outcome more consistent with the NEO and revenue and pricing principles than the other possible alternatives.

Metering services and ancillary network services

As we propose reclassifying these services a change in regulatory arrangements will be made regardless of the control mechanism we determine.

Public lighting

Our decision to apply caps on the prices of individual services is consistent with the current regulatory arrangements in Queensland.

2.4.4 Desirability of consistency between regulatory arrangements

We consider consistency across jurisdictions is generally desirable but is not primary to our consideration in this instance. Desirability needs to be weighed against the other factors under clause 6.2.5(c) of the rules. The outcomes under the factors reveal outcomes that further the national electricity objectives and are consistent with the revenue and pricing principles.

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. Under caps on 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, distributors will be able to compete by charging below the cap. However, unlike under a WAPC, distributors will not be able to compensate for such reductions by increasing the price on non-competitive services. This will enhance cost reflective prices for both competitive and non-competitive services.

2.4.6 Formulae for alternative control services

We are required to set out our proposed approach to the formulae that give effect to the control mechanisms for alternative control services in this F&A paper.²⁵⁷ We must include the formulae as set out below in our distribution determination, unless we consider that unforeseen circumstances justify departing from the formulae as set out in the F&A paper.²⁵⁸

Alternative control services where a price cap applies

Below is a proposed formula to apply to alternative control services where a price cap applies. We consider that the formula gives effect to the cap on the prices of individual services:

$$p_i^t = p_i^{t-1}(1 + \Delta CPI_t)(1 - X_i^t) + A_i^t$$

Where:

p_i^{t-1} is the cap on the price of service i in year t-1

p_i^t is the price of service i in year t

ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1. For example, for the 2015-16 year, t-2 is December 2013 and t-1 is December 2014 and in the 2016-17 year, t-2 is December 2014 and t-1 is December 2015 and so on.

X_i^t is the X-factor for service i in year t. To be decided upon in the final decision (if required).

A_i^t is an adjustment factor for service i in year t. Likely to include, but not limited to adjustments for residual charges when customers choose to replace assets before the end of their economic life.

For the avoidance of doubt, when setting the prices for 2015-16, p_i^t are prices being set for year 2015-16 and p_i^{t-1} are prices from the year 2014-15.

Alternative control services provided on a quoted basis

In our preliminary position paper, we proposed to use the above formula for quoted services and for clarity, the overall price of a quoted service is derived from one or more input prices. For example, a labour rate or material cost. Where this is the case, the price that relates to the input cost is substituted for the price term p_i^{t-1} . That is, we would not fix final prices, but rather set a formula and have fixed input costs. This would have the effect of capping the price paid by end users.

²⁵⁷ NER, clause 6.8.1(b)(2)(ii).

²⁵⁸ NER, clause 6.12.3(c1).

The Qld distributors did not support our proposed approach.²⁵⁹ Energex submitted that the proposed formula would result in a schedule of price caps for those services charged on a fixed fee basis and a schedule of price caps on the different inputs used in the provision of quoted services, adjusted annually by CPI and X-factor. This is a departure from the cost build-up approach and formula applicable in the current regulatory control period for quoted services.²⁶⁰

Having considered Energex's submission, our approach is to retain the current cost-build up approach for Energex and apply the same formula to Ergon Energy's quoted services.²⁶¹

$$\text{Price} = \text{Labour} + \text{Contractor Services} + \text{Materials} + \text{Capital Allowance}^{262}$$

where:

- Labour (including on costs and overheads)—consists of all labour costs directly incurred in the provision of the service which may include but is not limited to labour on costs, fleet on costs and overheads. The labour cost for each service is dependent on the skill level and experience of the employee/s, time of day/week in which the service is undertaken, travel time, number of hours, number of site visits and crew size required to perform the service.
- Contractor services (including overheads)—reflects all costs associated with the use of external labour in the provision of the service, including overheads and any direct costs incurred as part of performing the service. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred as part of performing the service, for example permits for road closures or footpath access, are passed on to the customer.
- Materials (including overheads)—reflects the cost of materials directly incurred in the provision of the service, material storage and logistics on costs and overheads.
- Capital allowance—represents a return on and return of capital for non-system assets (for example vehicles, IT and tools) used in the provision of the service.²⁶³

In our distribution determination we will establish the initial price cap on labour rates for quoted services. These labour rates will be escalated on an annual basis in subsequent years of the regulatory control period. We will consult and decide on the appropriate method of labour cost escalation in our distribution determination.

Adopting this approach means the Qld distributors need not identify every cost input that may be required in performing an alternative control service on a quoted basis. For example, Energex stated in its submission that in 2012–13 it issued over 1000 different types of materials to provide alternative control services.²⁶⁴ If we were to adopt the formula outlined in our preliminary position F&A, we would need to approve in excess of 1000 price caps to account for different inputs like material types. This would impose high administrative costs on the distributors and us. More importantly, we consider that our proposed approach will result in more cost-reflective prices.

²⁵⁹ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 42; Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 11.

²⁶⁰ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 43.

²⁶¹ Our preference to apply the same formula to both Queensland distributors is for the sake of consistency. Ergon Energy will be able to recover costs previously classified as 'one off costs' in this formula, primarily through the contractor services cost category.

²⁶² GST has not been accounted for.

²⁶³ While we propose including capital allowance in the formula, it does not mean we will approve this as a prudent cost in the determination.

²⁶⁴ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 43.

3 Incentive schemes

This attachment sets out our proposed approach to the application of a range of incentive schemes to the Qld distributors for the next regulatory control period. At a high level, our proposed approach is to apply the:

- service target performance incentive scheme with a financial penalty or reward of ± 2 per cent revenue at risk
- new efficiency benefit sharing scheme
- capital expenditure sharing scheme
- demand management incentive scheme including a demand management innovation allowance of \$5 million in total over five years.

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 the Qld distributors in the next regulatory control period.

Our national distribution STPIS²⁶⁵ provides a financial incentive to distributors to maintain and improve service performance. The STPIS aims to safeguard that cost efficiencies encouraged under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributors' incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (NEO).

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

- The service standards factor (s-factor) adjustment to the annual revenue allowance for standard control services rewards (or penalises) distributors for improved (or diminished) service compared to predetermined targets. Targets relate to service parameters pertaining to reliability and quality of supply, and customer service.
- A guaranteed service level (GSL) component composed of direct payments to customers²⁶⁶ experiencing service below a predetermined level.²⁶⁷

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

- the maximum revenue at risk under the STPIS
- how the distributor's network will be segmented
- the applicable parameters for the s-factor adjustment of annual revenue across customer service, reliability and quality of supply components

²⁶⁵ AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009.

²⁶⁶ Except where a jurisdictional electricity GSL requirement applies.

²⁶⁷ 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.

- 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.

Distributors can propose to vary the application of the STPIS in their regulatory proposal.²⁶⁸ We can accept or reject the proposed variation in our determination. Each applicable year we will calculate a distributor's s-factor based on its service performance in the previous year against targets, subject to the revenue at risk limit. Our national STPIS includes a banking mechanism, allowing distributors to propose delaying a portion of the revenue increment or decrement for one year to reduce price volatility for customers.²⁶⁹ A distributor proposing a delay must provide in writing its reasons and justification for considering that the delay will result in reduced price variations to customers.

Our national STPIS currently applies to the Qld distributors. The Qld distributors are currently subject to financial penalty or reward of ± 2 per cent through an s-factor adjustment to revenue. The GSLs are a jurisdictional requirement, so the GSL component of the STPIS will not apply.²⁷⁰

3.1.1 AER's proposed approach

Our proposed approach is to continue to apply the national STPIS to the Qld distributors in the next regulatory control period. Ergon Energy supported this position.²⁷¹ Our proposed approach to applying the national STPIS in the next regulatory control period will be to:

- set revenue at risk for each distributor within the range ± 2 per cent as submitted by Energex and Ergon Energy.²⁷²
- segment the network according to feeder categories (CBD, urban and short rural for Energex and urban, short rural and long rural for Ergon Energy²⁷³) in the Qld jurisdictional distribution licence conditions
- set applicable reliability of supply (system average interruption duration index or SAIDI and system average interruption frequency index or SAIFI) and customer service (telephone answering) parameters²⁷⁴
- set performance targets based on the distributors' 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 targets²⁷⁵

²⁶⁸ AER, *Electricity distribution network service providers – service target performance incentive scheme*, 1 November 2009, clause 2.2.

²⁶⁹ AER, *Electricity distribution network service providers – service target performance incentive scheme*, 1 November 2009, clauses 2.5(d) and (e).

²⁷⁰ AER, *Final framework and approach paper, application of schemes, Energex and Ergon Energy 2010–15*, November 2008, p. 5.

²⁷¹ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 14.

²⁷² Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 47; Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 15.

²⁷³ As noted by Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 15.

²⁷⁴ Energex and Ergon Energy supported our proposed continuation of SAIDI and SAIFI, Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 47; Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 15.

- apply the methodology and value of customer reliability (VCR) values as indicated in our national STPIS to the calculation of incentive rates.

We will not apply the GSL component if the Qld distributors are subject to a jurisdictional GSL scheme.²⁷⁶ Energex and Ergon Energy supported this approach.²⁷⁷

We are aware of policy reviews indicating the need to reform the STPIS. The AEMC recently conducted a review of distribution reliability frameworks in the NEM.²⁷⁸ The Australian Energy Market Operator (AEMO) is currently conducting analysis on how willing consumers are to pay for improvements in network reliability.²⁷⁹ We consider there is likely to be inadequate time to review our national STPIS to incorporate the findings of these reviews before finalising our determinations for the Qld distributors.

3.1.2 AER's assessment approach

The rules require us to have regard to several factors in developing and implementing a STPIS for the Qld distributors.²⁸⁰ These include:

- Jurisdictional obligations
 - consulting with the authorities responsible for the administration of relevant jurisdictional electricity legislation
 - checking 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
 - 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 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 provide incentives that are sufficient to offset any financial incentives the distributor may have to reduce costs at the expense of service levels

²⁷⁵ Supported by Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 50.

²⁷⁶ The QCA is reviewing GSL arrangements as required by the Electricity Industry Code (Qld). The QCA's consultation process is ongoing. Material on this review is available at www.qca.org.au/electricity/service-quality/RevMinServStandLev15.php.

²⁷⁷ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 50; Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 14.

²⁷⁸ AEMC, *Review on national framework for distribution reliability*, 27 September 2013.

²⁷⁹ AEMO, *Value of customer reliability issues paper*, 11 March 2013; AEMC, *Advice on linking the reliability standard and reliability settings with VCR*, October 2013.

²⁸⁰ NER, clause 6.6.2(b).

- 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.²⁸¹

3.1.3 Reasons for AER's proposed approach

Our reasons for proposing to apply the STPIS to the Qld distributors in the next regulatory control period are set out below.

Jurisdictional obligations

In Qld, the Queensland Competition Authority (QCA) administers and monitors compliance with the distribution licence conditions set out in the Electricity Industry Code. As required by the rules, we will consult with the QCA and the Department of Energy and Water Supply (DEWS), as jurisdictional authorities, on the implementation of the STPIS²⁸² before finalising our distribution determination.

Our proposed approach to applying the STPIS in Qld does not intend to compromise the distributors' ability to comply with jurisdictional licence obligations or create duplication. We intend doing this by not:

- setting service performance targets lower than the minimum service requirements in the licence conditions; and
- applying the GSL component of our national STPIS while QCA's guaranteed customer service arrangements remain in place. The Qld distributors agree with our proposal not to apply the GSL component.²⁸³

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.²⁸⁴ Energex and DEWS submitted that customers' willingness to pay for improved service performance is not a priority in the current environment where customers are concerned with living costs. Additionally, approaches to reliability standards are under review in Qld which may see a reduction in the requisite standards.²⁸⁵

We consulted our Consumer Challenge Panel (CCP)²⁸⁶ on the application of STPIS. Some members of the CCP considered that we should set revenue at risk at zero for the next regulatory control period. This would mean that the Qld distributors would not be rewarded for exceeding service standards (or penalised for failing to do so). We understand the views expressed by the CCP (and in other submissions) which reflect a concern the STPIS rewards are too easily achieved by the distributors. We acknowledge it is important that service targets are set in such a manner that

²⁸¹ AER, *Final decision: Electricity distribution network service providers Service target performance incentive scheme*, 1 November 2009.

²⁸² NER, clause 6.6.2(b)(1).

²⁸³ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 50; Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 14.

²⁸⁴ NER, clause 6.6.2(b)(3)(vi).

²⁸⁵ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 47; Department of Energy and Water Supply, *Submission on the AER's preliminary framework and approach for Energex and Ergon Energy*, 25 February 2014, p. 3.

²⁸⁶ When referring to the CCP, we are referring to CCP sub-panel 2. Sub-panel 2 members are Ms Bev Hughson, Ms Fiona McLeod, Mr Bruce Mountain, Mr Bob Lim and Mr Hugh Grant.

achieving a reward is no certainty. Indeed, if the service targets are set appropriately, customers should expect to benefit as often as distributors over the medium term. Reducing the STPIS revenue at risk could take away benefits that customers may otherwise have enjoyed. Consequently, we consider the STPIS, as a key component of the incentive based regulatory framework, should continue to influence the behaviour of the Qld distributors. The interrelationship between the STPIS with other aspects of the regulatory framework, discussed below, also need to be considered as no single incentive scheme operates in isolation.

Under the STPIS, the distributors' 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 energy during a supply interruption. As outlined in our national STPIS, we will use VCR estimates at different stages of our annual s-factor calculation to:

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

The VCR estimates in our national STPIS are taken from studies conducted for the Essential Services Commission Victoria and Essential Services Commission of South Australia.²⁸⁷ The distributors may propose an alternative VCR estimate, supported by details of the calculation methodology and research, in their regulatory proposals.²⁸⁸

The AEMC recently conducted a review of distribution reliability outcomes and standards in the NEM, proposing a more significant role for the STPIS.²⁸⁹ AEMO is currently reviewing approaches to estimating VCR and it is unclear when AEMO will propose new VCR estimates. We may undertake a review of our national STPIS once these studies are complete. Any change to the STPIS would be subject to the distribution consultation procedures in the rules.²⁹⁰ We consider there is insufficient time to conduct a comprehensive review of the STPIS before the Qld distributors submit proposals in October 2014 for the next regulatory control period. Therefore our preliminary position was to apply the national STPIS in its current form and monitor ongoing work. Ergon Energy's submission supported this approach.²⁹¹ Energex submitted that if the AEMO estimates are available prior to the release of our final F&A, then it is in the best interests of all parties that the updated VCR be used. This is because it will provide confidence that the true value that customers place on reliability is reflected.²⁹²

We acknowledge Energex's point. However AEMO has not issued new VCRs and it is unclear when it will. We are therefore not inclined to amend our preliminary position. Having said that, the F&A only sets out our proposed approach to applying the STPIS. That approach is not binding for the distribution determination. AEMO may issue new VCRs in sufficient time for us to consider their impact on the STPIS for the distribution determination. If so, we will consider this issue at that time and consult with the Qld distributors.

²⁸⁷ 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.

²⁸⁸ AER, *Electricity distribution network service providers, Service target performance incentive scheme*, November 2009, p. 9.

²⁸⁹ AEMC, *Draft report: Review of distribution reliability outcomes and standards*, 28 November 2012.

²⁹⁰ NER, Part G.

²⁹¹ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 15.

²⁹² Energex, *Responses to the AER's framework and approach preliminary positions*, 19 February 2014, p. 48.

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.

Distributor incentives under the STPIS

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

The rules require us to consider past performance of the distributor's network in developing and implementing the STPIS.²⁹³ Our preferred approach, supported by Energex,²⁹⁴ is to base performance targets on the distributors' average performance over the past five regulatory years.²⁹⁵ Using an average calculated over multiple years instead of applying performance targets based solely on the most recent regulatory year limits the distributors' incentive to underperform in the final year of a regulatory control period to make future targets less onerous.

Our national STPIS limits variability in penalties and rewards caused by circumstances outside the distributors' 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.²⁹⁶ In Qld, the STPIS will interact with our expenditure and demand management incentive schemes.

The efficiency benefit sharing scheme (EBSS) provides distributors 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 distributors may have to reduce costs at the expense of service levels.²⁹⁷

In setting STPIS performance targets, we will consider both completed and planned reliability improvements expected to materially affect network reliability performance.²⁹⁸

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

²⁹³ NER, clause 6.6.2(b)(3)(iii).

²⁹⁴ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 48.

²⁹⁵ Subject to any modifications required under clauses 3.2.1(a) and (b) of the national STPIS.

²⁹⁶ NER, clause 6.6.2(b)(3)(iv).

²⁹⁷ NER, clause 6.6.2(b)(3)(v).

²⁹⁸ Included in the distributor's approved forecast capex for the next period.

The rules require us to consider the possible effects of the STPIS on the distributors' 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. The interaction of the schemes is an important factor, also noted by some CCP members.²⁹⁹ That is, the STPIS provides an incentive for distributors to maintain network performance balanced against incentives that encourage them to defer or avoid network investment.

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

3.2 Efficiency benefit sharing scheme

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

3.2.1 AER's proposed approach

We propose applying our new EBSS³⁰⁰ to the Qld distributors for the 2015–20 regulatory control period. Energex and the CCP supported our preliminary position, while Ergon Energy has noted our intention to apply the scheme.³⁰¹ Our distribution determination for Energex and Ergon Energy 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 distributors and consumers of opex efficiency gains and efficiency losses.³⁰² We must also have regard to the following factors in developing and implementing the EBSS:³⁰³

- 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

²⁹⁹ Consumer Challenge Panel discussion with AER staff on 5 March 2014.

³⁰⁰ AER, *Efficiency benefit sharing scheme*, 29 November 2013.

³⁰¹ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 51; Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 15; Consumer Challenge Panel discussions with AER staff on 5 March 2014.

³⁰² NER, clause 6.5.8(a).

³⁰³ NER, clause 6.5.8(c).

- 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 Qld distributors in their current regulatory control period.³⁰⁴ 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.³⁰⁵ 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.³⁰⁶

In this section we set out why we propose to apply the new EBSS to the Qld distributors 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.³⁰⁷ This reasoning extends to the factors we must have regard to in implementing the scheme.

The EBSS must provide for a fair sharing of efficiency gains and losses.³⁰⁸ 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.³⁰⁹ 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.³¹⁰

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.³¹¹ For instance, the combined effect of our forecasting approach and the EBSS is that opex efficiency gains or losses are shared approximately 30:70 between distributors and consumers. This means for a one dollar efficiency saving in opex the distributor keeps 30 cents of the benefit while consumers keep 70 cents of the benefit.

³⁰⁴ AER, *Electricity distribution network service providers, efficiency benefit sharing scheme*, 26 June 2008.

³⁰⁵ 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.

³⁰⁶ AER, *Efficiency benefit sharing scheme for electricity network service providers*, 29 November 2013.

³⁰⁷ 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.

³⁰⁸ NER, clause 6.5.8(a).

³⁰⁹ NER, clauses 6.5.8(c)(3) and 6.5.8(a).

³¹⁰ NER, clause 6.5.8(c)(2).

³¹¹ NER, clause 6.5.8(c)(1).

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.

Example 1: How the EBSS operates

Assume that in the first regulatory period, a distributor's forecast opex is \$100 million per annum (p.a.).

Assume that during this period the distributor delivers opex equal to the forecast for the first three years. Then, in the fourth year of the regulatory period, the distributor implements a more efficient business practice for maintaining its assets. As a result, the distributor will be able to deliver opex at \$95 million p.a. for the foreseeable future.

This efficiency improvement affects regulated revenues in two ways:

1. Through forecast opex. If we use the penultimate year of the regulatory period to forecast opex in the second regulatory period, the new forecast will be \$95 million p.a. If the efficiency improvement is permanent, all else being equal, forecast opex will also be expected to be \$95 million p.a. in future regulatory periods.
2. Through EBSS carryover amounts. The distributor receives additional carryover amounts so that it receives exactly six years of benefits from an efficiency improvement. Because the distributor has made an efficiency improvement of \$5 million p.a. in Year 4, to ensure it receives exactly six years of benefits, it will receive annual EBSS carryover amounts of \$5 million in the first four years (Years 6 to 9) of the second regulatory period.

As a result of these effects, the distributor will benefit from the efficiency improvement in Years 4 to 9. This is because the annual amount the distributor receives through the forecast opex and EBSS building blocks (\$100 million) is more than what it pays for opex (\$95 million) in each of these years.

Consumers benefit from Year 10 onwards after the EBSS carryover period has expired. This is because what consumers pay through the forecast opex and EBSS building blocks (\$95 million) is lower from Year 10 onwards.

Table 7 (below) provides a more detailed illustration of how the benefits are shared between distributors and consumers over time.

(Example 1 continued)

Table 7: Example of how the EBSS operates

Year	Regulatory period 1					Regulatory period 2					Future
	1	2	3	4	5	6	7	8	9	10	
Forecast (F_t)	100	100	100	100	100	95	95	95	95	95	95 p.a.
Actual (A_t)	100	100	100	95	95	95	95	95	95	95	95 p.a.
Underspend ($F_t - A_t = U_t$)	0	0	0	5	5	0	0	0	0	0	0 p.a.
Incremental efficiency gain ($I_t = U_t - U_{t-1}$)	0	0	0	5	0	0*	0	0	0	0	0 p.a.
Carryover (I_1)		0	0	0	0	0					
Carryover (I_2)			0	0	0	0	0				
Carryover (I_3)				0	0	0	0	0			
Carryover (I_4)					5	5	5	5	5		
Carryover (I_5)						0	0	0	0	0	
Carryover amount (C_t)						5	5	5	5	0	0 p.a.
Benefits to distributor ($F_t - A_t + C_t$)	0	0	0	5	5	5	5	5	5	0	0 p.a.
Benefits to consumers ($F_t - (F_t + C_t)$)	0	0	0	0	0	0	0	0	0	5	5 p.a.
Discounted benefits to distributor**	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 do not know actual opex for year 5. Consequently this is not reflected in forecast opex for the second period. That means an underspend in year 6 will reflect any efficiency gains made in both year 5 and year 6. To ensure the carryover rewards for year 6 only reflect incremental efficiency gains for that year we subtract the incremental efficiency gain in year 5 from the total underspend. In the example above, $I_6 = U_6 - (U_5 - U_4)$.
 ** Assumes a real discount rate of 6 per cent.
 *** As a result of the efficiency improvement, forecast opex is \$5 million p.a. lower in nominal terms. The estimate of \$58.7m is the net present value of \$5 million p.a. delivered to consumers annually from year 11 onwards.

Table 8 sums the discounted benefits to distributors and consumers from the bottom two rows of Table 7. As illustrated below, the benefits of the efficiency improvement are shared approximately 30:70 in perpetuity between the distributor and consumers.

Table 8: Sharing of efficiency gains—Year 4 forecasting approach, with EBSS

	NPV of benefits of efficiency improvement ¹	Percentage of total benefits
Benefits to distributor	\$26.1 million	30 per cent
Benefits to consumers	\$62.3 million	70 per cent
Total	\$88.3 million	100 per cent

In implementing the EBSS we must also have regard to any incentives distributors may have to capitalise expenditure.³¹² 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. When the CESS and EBSS are applied, incentives will be relatively balanced, and distributors 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:³¹³

- 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.³¹⁴ 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 distributors may otherwise receive a penalty for increasing opex without a corresponding reward for decreasing capex.³¹⁵

Energex, while supportive of our intention to apply the new EBSS, raised three concerns in its submission. First, Energex submitted that we should recognise uncontrollable costs which would qualify for a pass-through if a distributor applied or where a pass-through would be permitted but for the materiality threshold.³¹⁶ Energex made this submission in respect of EBSS and CESS, which we have responded to collectively below.

We previously considered these issues in response to Energex's submission to our draft capital expenditure incentive guideline and EBSS.³¹⁷ We considered amendments to either the CESS or EBSS were not needed to address these issues. For instance:

- A distributor would avoid a penalty for increased opex (capex) if we approved the opex (capex) as part of a pass-through event. If a distributor wishes to avoid a penalty it should submit a pass-through application. If we approve an increase in regulated revenue after assessing the pass-through application, then it is a business decision for the distributor as to whether it increases its tariffs to recover the additional revenue.
- We acknowledge the EBSS will reward or penalise distributors for some forecasting error associated with uncontrollable events. However, on the whole, the risk of uncontrollable events

³¹² NER, clause 6.5.8(c)(4).

³¹³ NER, clause 6.5.8(c)(5).

³¹⁴ 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.

³¹⁵ 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.

³¹⁶ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 51–52.

³¹⁷ AER, *Explanatory statement efficiency benefit sharing scheme*, November 2013, pp. 19–20; AER, *Explanatory statement capital expenditure incentive guideline*, November 23013, pp. 38–39.

presents both upside and downside risk to distributors. Further, distributors would only have an incentive to identify uncontrollable events that increase their frequent costs. Therefore, we do not think there is a compelling argument to share the cost of uncontrollable events differently to all other costs facing distributors.

- We consider the risk borne by distributors for costs which would have qualified for a pass through if not for the materiality threshold, to be relatively immaterial. We see no reason why relatively immaterial costs should be excluded from the EBSS or CESS.

Second, Energex submitted that it is concerned that the current EBSS (version 1) and our expenditure forecast assessment guideline are not entirely compatible.³¹⁸ Energex explained that it has non-recurrent costs in its proposed base year opex and in all alternative base years such that there is no representative base year without adjustment for one-off costs. The sharing of efficiency gains/losses under the current EBSS relies heavily on adoption of the unadjusted revealed cost into the next regulatory control period.

We consider that the current EBSS and our expenditure forecast assessment guideline are compatible. To align the opex allowance with the opex criteria we may adjust the base opex to remove inefficient expenditure. We are required to have regard to whether an opex forecast is consistent with any incentive schemes that apply to a distributor.³¹⁹ Consequently, when determining whether to adjust or substitute base year expenditure, we will also have regard to whether rewards or penalties accrued under the EBSS will provide fair sharing of efficiency gains or losses between the distributor and its customers.³²⁰

Third, Energex submitted that the reclassification of services from standard control to alternative control may also have implications for the application of the EBSS.³²¹ The current EBSS addresses this issue. It states that where a standard control service does not remain a standard control service in the following regulatory control period, we may remove the opex relating to that service from the actual and forecast opex figures used to calculate carryover amounts.³²² In determining whether to do so, we will consider factors such as the materiality of the impact of the carryover amounts.³²³ We expect this to be relevant for our proposed reclassification of type 5 and 6 metering services from standard control to alternative control.

Canegrowers does not support the wholesale application of incentive schemes to the Qld distributors. It submitted that the incentive schemes are not designed in accordance with the National Electricity Objective as they are not in the long term interests of consumers.³²⁴ We do not agree with this statement. The basis of the National Electricity Market is incentive regulation using the building block approach to determine an allowable level of revenue.³²⁵ This approach limits a natural monopoly's ability to exercise market power, while maintaining strong incentives for distributors to minimise costs and to innovate. Firms that spend less than forecast are allowed to keep a proportion of the savings. There are also targeted incentives to promote specific goals like reliability and demand management.³²⁶

³¹⁸ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, pp. 51–52.

³¹⁹ NER, clause 6.5.6(e)(8).

³²⁰ AER, *Explanatory statement expenditure forecast assessment guideline*, November 2013, p. 63.

³²¹ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 52.

³²² AER, *Electricity distribution network service providers efficiency benefit sharing scheme*, June 2008, p. 9.

³²³ AER, *Electricity distribution network service providers efficiency benefit sharing scheme*, June 2008, p. 7.

³²⁴ Canegrowers, *AER Framework and approach: Energex and Ergon Energy*, 24 February 2014, p. 6.

³²⁵ NER, clause 6.18.5.

³²⁶ AER, *Explanatory statement, efficiency benefit sharing scheme for electricity network service providers*, November 2013, pp. 5–10.

Canegrowers' submitted the EBSS and CESS shield distributors from a competitive environment.³²⁷ Canegrowers' submitted that the sharing of efficiency gains (or losses) at 30:70 between distributors and consumers does not reflect a competitive environment. Rather, the distributor and its shareholders should bear the risk of investments and not consumers and the power of the incentive should be set at 100:0.³²⁸ We point to the incentive basis of the electricity regime.³²⁹ As discussed above, our incentive schemes encourage distributors to make efficient decisions. They give distributors an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers.

Incentives for opex and capex are balanced (30 per cent) and constant. They are also balanced with the incentives under our STPIS. This encourages businesses to make efficient decisions on when and what type of expenditure to incur, in order to meet service reliability targets.

The ex post review complements the CESS to provide distributors with an additional incentive to help ensure that any overspends are efficient and prudent. Under the CESS a business bears 30 per cent of the overspend. However, if the overspend is found to be inefficient, the ex post reviews mean the business could bear 100 per cent of the inefficient overspend.³³⁰

3.3 Capital expenditure sharing scheme

The CESS provides financial rewards for distributors whose capex becomes more efficient and imposes 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 Qld distributors in the next regulatory control period.

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

The CESS works as follows:

- We calculate the cumulative underspend or overspend for the current regulatory control period in net present value terms.
- We apply the sharing ratio of 30 per cent to the cumulative underspend or overspend to work out what the distributor's share of 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.³³¹ We can also make further adjustments to account for deferral of capex and ex post exclusions of capex from the RAB.
- The CESS payments will be added or subtracted to the distributor's regulated revenue as a separate building block in the next regulatory control period.

³²⁷ Canegrowers, *AER Framework and approach: Energex and Ergon Energy*, 24 February 2014, p. 6.

³²⁸ Canegrowers, *AER Framework and approach: Energex and Ergon Energy*, 24 February 2014, p. 6.

³²⁹ AER, *Better regulation: expenditure incentives (factsheet)*, November 2013, pp. 1–2; AER, *Explanatory statement, capital expenditure incentive guideline for electricity network service providers*, November 2013, p. 5.

³³⁰ AER, *Explanatory statement, capital expenditure incentive guideline for electricity network service providers*, November 2013, p. 10.

³³¹ 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.

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

We propose to apply the CESS, as set out in our capex incentives guideline,³³² to Energex and Ergon Energy in the next regulatory control period.

3.3.2 AER's assessment approach

In deciding whether to apply the CESS to a distributor, and the nature and details of any CESS to apply to a distributor, we must:³³³

- make that decision in a manner that contributes to the capex incentive objective³³⁴
- consider the CESS principles,³³⁵ capex objectives,³³⁶ 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

Our proposed approach is to apply the CESS to the Qld distributors in the next regulatory control period as we consider this will contribute to the capex incentive objective. Ultimately, the aim is that consumers pay only for efficient and prudent capex undertaken by distributors. That is, our capex incentive measures mean that consumers pay only a portion of efficient overspends, pay nothing for inefficient overspends and consumers share in the benefits when a distributor is able to spend less than its forecast capex allowance. Origin, Regional Development Australia Far North Queensland and Torres Strait, Queensland Farmers' Federation and the CCP³³⁷ supported our preliminary position. Energex accepted our preliminary position,³³⁸ while Ergon Energy simply noted our intention to apply the CESS.

Qld distributors are 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.³³⁹ The guideline specifies that in most circumstances we will apply a CESS, in conjunction with forecast

³³² AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9.

³³³ NER, clause 6.5.8A(e).

³³⁴ NER, clause 6.4A(a); the capex criteria are set out in clause 6.5.7(c) of the NER.

³³⁵ NER, clause 6.5.8A(c).

³³⁶ NER, clause 6.5.7(a).

³³⁷ Origin, *Framework and approach for Energex and Ergon Energy for period commencing 1 July 2015*, 13 February 2014, p. 3; Regional Development Australia Far North Queensland and Torres Strait Inc, *Submission to the AER preliminary framework and approach for Energex and Ergon Energy*, 19 February 2014, p. 3; Queensland Farmers' Federation, *Submission on the preliminary positions paper*, 24 February 2014, p. 2; Consumer Challenge Panel discussions with AER staff on 5 March 2014.

³³⁸ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 51; Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 15.

³³⁹ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9.

depreciation to roll-forward the RAB.³⁴⁰ 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 we propose the Qld distributors 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.³⁴¹ Because of this a distributor may choose to spend capex earlier, or on capex when it may otherwise have spent on opex, or less on capex at the expense of service quality—even if it may not be efficient to do so.

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

Canegrowers do not support our proposed application of the CESS stating that the scheme shields distributors from a competitive environment.³⁴² As discussed above, the National Electricity Market is based on an incentives regime. Canegrowers' submission does not appear to acknowledge this basis of the regime.

Historically, we were required to add all capex to a distributor's RAB regardless of whether it was efficient, or exceeded the approved forecast. This meant consumers were paying prices that reflected all of a distributor's capex which may have included inefficient capex. However, in addition to the ex post measures discussed at section 3.2 above, we now have the ability to exclude inefficient related party margins and capitalised opex that does not benefit consumers. Overall, the CESS will provide distributors with clear incentives to pursue efficiency gains throughout the full regulatory control period.³⁴³

When the CESS, EBSS and STPIS apply to distributors, incentives for opex, capex and service are balanced. They give distributors an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers. Incentives for opex and capex are balanced (30 per cent) and constant. They are also balanced with the incentives under our STPIS. This encourages distributors

³⁴⁰ AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 10–12.

³⁴¹ 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.

³⁴² Canegrowers, *AER Framework and approach: Energex and Ergon Energy*, 24 February 2014, p. 6. We have addressed Canegrowers' submission on the CESS as part of our discussion on the EBSS.

³⁴³ AER, *Explanatory statement, capital expenditure incentive guideline for electricity network service providers*, November 2013, p. 10

to make efficient decisions on when and what type of expenditure to incur, in order to meet service reliability targets.

3.4 Demand management incentive scheme

This section sets out our proposed approach and reasons for applying a demand management incentive scheme (DMIS) to the Qld distributors in the next regulatory control period.³⁴⁴

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.³⁴⁵ 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.³⁴⁶ To meet this requirement, and motivated by the need to improve Qld distributors' capability in the demand management area, we implemented a DMIS in our distribution determinations for the current regulatory period.

The current DMIS includes two components:

- Part A provides for an innovation allowance (DMIA) to be incorporated into each distributor's revenue allowance for each year of the regulatory control period. Distributors prepare annual reports on their expenditure under the DMIA³⁴⁷ in the previous year, which we then assess against specific criteria.
- Part B compensates distributors for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A for distributors under a weighted average price cap. In the current regulatory control period, Qld distributors are subject to a revenue cap form of control. As the revenue cap is expected to continue in the next regulatory control period, Part B remains not relevant to Qld distributors.

Currently only Part A of the scheme applies to the Qld distributors.

³⁴⁴ 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.

³⁴⁵ 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.

³⁴⁶ NER, clause 6.6.3(a).

³⁴⁷ The DMIA excludes the costs of demand management initiatives approved in our determination for the 2009–14 period or under the D-factor scheme.

3.4.1 AER's proposed approach

Our proposed approach, supported by the Qld distributors,³⁴⁸ is to continue applying the DMIS to the Qld distributors in the next regulatory control period.

We acknowledge the need to reform the existing demand management incentive arrangements in Qld. The COAG Energy Council (formerly SCER) is currently considering a series of rule changes³⁴⁹ proposed by the AEMC in its Power of Choice review³⁵⁰ examining distributor incentives to pursue efficient alternatives to network augmentation. This will include new rules and principles guiding the design of a new DMIS. We may develop and implement a new DMIS during the next regulatory control period, depending on the progress of the rule change process. For these reasons, we propose to allow a \$5 million DMIA (\$1 million each year). The Qld distributors sought the continuation of this allowance.³⁵¹ The CCP were not in favour of providing a DMIA. They considered the payment and its use by distributors is not subject to sufficient rigour, and in their view, is not in the interests of consumers.³⁵²

Energex and Ergon Energy both submitted that we should not apply a new DMIS during the next regulatory control period.³⁵³ Ergon Energy further submitted that as a matter of procedural fairness any revised scheme should not apply to it in the next regulatory period.³⁵⁴ We do not agree with these points. We do not consider it appropriate to lock in a scheme now when this subject is currently being considered under the Power of Choice review. Therefore, we cannot provide any assurance that a new DMIS will not be applied within period. The F&A is only intended to provide an outline of our proposed approach and is not binding.³⁵⁵ It is our intention to have a demand management scheme and we would want to adopt a revised scheme, subject to the requirements of the rules, which may include transitional provisions requiring or allowing us to apply a new scheme or some variations within 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 the Qld distributors.³⁵⁶ These are:

- Benefits to consumers
 - 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

³⁴⁸ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 45; Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 16.

³⁴⁹ SCER, *Demand side participation – proposed rule changes*, 18 September 2013.

See: www.scer.gov.au/workstreams/energy-market-reform/demand-side-participation/proposed-rule-changes.

³⁵⁰ AEMC, *Final report, Power of choice review – giving consumers' choice in the way they use electricity*, 30 November 2012.

³⁵¹ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 50; Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 16.

³⁵² Consumer Challenge Panel discussion with AER staff, 5 March 2014.

³⁵³ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 50; Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 16.

³⁵⁴ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 16.

³⁵⁵ NER, clause 6.12.3.

³⁵⁶ NER, clause 6.6.3(b).

- the effect of a particular control mechanism (that is, price as distinct from revenue regulation) on a distributor's incentives to adopt or implement efficient non-network alternatives
- the effect of classification of services on a distributor's incentive to adopt or implement efficient embedded generator connections
- the extent the distributor is able to offer efficient pricing structures
- the possible interactions between a DMIS and the other incentive schemes.

3.4.3 Reasons for AER's proposed approach

This section outlines the reasons for our proposed approach to apply the DMIS to Qld distributors 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.³⁵⁷

We assess projects for which distributor's apply for DMIA funding under a specific set of criteria. The DMIA aims to enhance distributors' 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 studies³⁵⁸ to date 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.³⁵⁹ We consider that

³⁵⁷ NER, clause 6.6.3(b)(1).

³⁵⁸ For example, Oakley Greenwood, *Valuing reliability in the national electricity market, final report*, March 2011. This report was prepared for AEMO.

³⁵⁹ NER, clause 6.6.3(b)(2).

a revenue cap form of control does not provide a disincentive for the Qld distributors to reduce the quantity of electricity as approved regulated revenues are not dependent on the quantity of electricity sold. That is, under a form of control where revenue is at least partially dependent on the quantity of electricity sold (for example, a price cap), a successful demand management program that causes a reduction in demand may result in less revenue for a distributor. A revenue cap avoids this scenario.

We are also required to consider the effect of service classification on a distributor's incentive to adopt or implement efficient embedded generator connections.³⁶⁰ We consider our proposed application of the DMIS meets this requirement as Qld distributors 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.³⁶¹ 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 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.

At present, Qld distributors' ability to adopt more efficient price signals is constrained by the low penetration of the required metering and other enabling technologies. We consider that moves to efficient pricing, enabled by 'smarter' grid technologies will have a significant impact on distribution network utilisation in the future. Additionally, retail pricing tariffs have not in the past mirrored the cost reflective distribution tariffs approved by us. While the Qld Government is considering reforms to retail tariffs, the DMIA incentivises distributors to trial measures that will assist the transition of networks to more efficient pricing.

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 Qld, we must consider how it could potentially interact with our other incentive schemes.³⁶² Neither our expenditure incentive schemes (EBSS and CESS) nor STPIS intend to discourage a distributor from using its DMIA.

While a distributor's annual opex allowance incorporates the DMIA, we may exclude the DMIA from the EBSS.³⁶³ 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.

³⁶⁰ NER, clause 6.6.3(b)(6).

³⁶¹ NER, clause 6.6.3(b)(3).

³⁶² NER, clause 6.6.3(b)(4).

³⁶³ 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 forecast assessment guideline (guideline)³⁶⁴ including the information requirements to the Qld distributors for the 2015–20 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 guideline outlines for distributors and interested stakeholders the types of assessments we will do to determine efficient expenditure allowances, and the information we require from the distributors to do so.

We were required to develop the guideline under the rules.³⁶⁵ The guideline is based on a nationally consistent reporting framework allowing us to compare the relative efficiencies of distributors and decide on efficient expenditure allowances. In the F&A we must set out our proposed approach to the application of the guideline.³⁶⁶

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

- models for assessing proposed replacement and augmentation capex
- benchmarking (including broad economic techniques and more specific analysis of expenditure categories)
- methodology, governance and policy reviews
- predictive modelling and trend analysis
- cost benefit analysis and detailed project reviews.³⁶⁷

We developed the guideline to apply broadly to all electricity transmission and distribution businesses. However, some customisation of the data requirements contained in the 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 by themselves be sufficient to assess 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 this analysis. We expect that these data customisation issues would be addressed through the Regulatory Information Notice that we will issue to the Qld distributors for the next regulatory control period.

³⁶⁴ We published this guideline on 29 November 2013. It can be located at www.aer.gov.au/node/18864.

³⁶⁵ NER, clauses 6.4.5, 6A.5.6, 11.53.4 and 11.54.4.

³⁶⁶ NER, clause 6.8.1(b)(2)(viii).

³⁶⁷ AER, *Explanatory statement: Expenditure assessment guideline for electricity transmission and distribution*, 29 November 2013.

5 Depreciation

Capital expenditure (capex) refers to expenditure on assets that are long lived. Distributors therefore recover the costs over the life of the asset rather than when the costs are incurred. This return of capital is also called depreciation. The alternative is to compensate distributors for costs entirely in the year they are incurred. This is the approach we use for operating expenses.

The distributors are provided an allowance for depreciation that is calculated on the existing regulatory asset base (RAB) and forecast additions or capex to the RAB. The proportion of depreciation related to forecast capex, like all forecasts, is subject to forecasting error. Once actual capex is known, it is possible to accurately determine what the depreciation allowance would have been. The issue under consideration in this attachment is whether the approach for depreciation in the RAB roll forward should employ the allowance based on forecast capex (forecast depreciation) or actual capex (actual depreciation) over the regulatory control period.

This attachment sets out our proposed approach to use forecast depreciation when rolling forward to establish the RAB at the commencement of the 2020–25 regulatory control period.

Once a distributor's capex allowance is determined, the funding for the approved capex program will be returned to the distributor for each year of the upcoming regulatory control period through the sum of:

- the forecast RAB multiplied by the weighted average cost of capital (WACC);³⁶⁸ and
- depreciation.³⁶⁹

As the capex allowance is set before the regulatory control period commences, a distributor has an incentive to spend less than the allowance and through these savings earn higher profits. Hence a distributor can 'keep the difference' between the allowance and what it cost to finance the actual capex until the end of the regulatory control period. Conversely, if a distributor spends more than its allowance, its revenue will not cover the overspend meaning that the distributor has to bear the cost of financing the overspend within the regulatory control period.³⁷⁰

The depreciation we use to roll forward the RAB at the end of the current regulatory control period 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.

³⁶⁸ The forecast RAB is the actual RAB at the end of the previous regulatory control period, plus any forecast net capex undertaken in the current regulatory control period, minus any actual depreciation (from assets in place prior to the start of the regulatory control period), minus any forecast depreciation (from net capex undertaken during the regulatory control period).

³⁶⁹ This is the sum of actual depreciation for assets in place prior to the start of the regulatory control period and forecast depreciation for net capex to be undertaken during the regulatory control period.

³⁷⁰ It is these incentives to reduce expenditure that make historical costs a good indicator of future costs where capex is recurrent and predictable. That is, a distributor's efficient costs are 'revealed' over time.

The choice of depreciation approach is one part of the overall capex incentive framework. In particular, the difference between the two approaches is the relative strength of the additional incentive to over-forecast or to underspend capex. This arises during the RAB roll forward at the end of the regulatory control period. To roll forward the RAB, we:

- start with the opening RAB for the regulatory control period
- add actual net capex for each year to the RAB
- remove forecast or actual depreciation for each year from the RAB
- determine the closing RAB at the end of the regulatory control period.

Regardless of the depreciation approach, we always update the RAB to reflect actual (prudent) capex. Therefore, when applying different depreciation approaches in the roll forward process, the closing RAB will only vary due to differences in the depreciation removed from this process.

Under a forecast depreciation approach, a distributor's RAB reduces to reflect the depreciation forecast set at the beginning of the regulatory control period. Whereas under an actual depreciation approach, the distributor's RAB reduces to reflect the re-calculated depreciation amount linked to each year's actual capex. Where actual capex differs from forecast, actual depreciation will be different to the depreciation forecast. Therefore, the two approaches result in different closing RABs at the end of the regulatory control period.

Through the different approaches to depreciation and other building blocks, the regulatory framework creates incentives for distributors to over forecast or to defer efficient expenditure. This can encourage distributors to pursue capex efficiency improvements that will ultimately benefit both the distributor and electricity consumers. The relative sharing ratio between the distributor and consumers will be determined by the year in which the capex overspend or underspend occurs, whether actual or forecast depreciation is used to roll forward the RAB, and the expected life of the asset.

Consumers benefit from improved efficiencies through lower regulated prices. Where a capital expenditure sharing scheme (CESS) is applied, the forecast depreciation approach 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.³⁷¹ In summary:

- If there is a capex overspend, actual depreciation will be higher than forecast depreciation. This means that when applying actual depreciation in the roll forward, the RAB will increase by a lesser amount than if forecast depreciation were used. Therefore, 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 when applying actual depreciation in the roll forward, 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.

³⁷¹ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 10–12.

The strength of capex reduction incentive from using actual depreciation to roll forward the RAB also varies with the expected 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 forecast depreciation to establish the RAB at the commencement of the 2020–25 regulatory control period for Energex and Ergon Energy. We consider this approach will provide sufficient incentives for the distributors to achieve capex efficiency gains over the 2015–20 regulatory control period.

5.2 AER's assessment approach

We must decide at 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.³⁷²

We are required to set out in our capex incentive guideline our process for determining which form of depreciation we propose to use in the RAB roll forward process.³⁷³ Our decision on whether to use actual or forecast depreciation must be consistent with the capex incentive objective.³⁷⁴ We must also have regard to:³⁷⁵

- the incentives the service provider has in relation to undertaking efficient capex, including as a result of the application of any incentive scheme or any other incentives under the rules
- substitution possibilities between assets with relatively short economic lives and assets with relatively long economic lives and the relative benefits of such asset types
- the extent to which capex incurred by the service provider has exceeded forecast capex, and the amount of that excess capex which is not efficient
- the Capital Expenditure Incentive Guideline
- the capital expenditure factors.

5.3 Reasons for AER's proposed approach

Consistent with our capex incentive guideline, we propose to use the forecast depreciation approach to establish the RAB at the commencement of the 2020–25 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 incentive guideline.³⁷⁶

Our approach is to apply forecast depreciation except where:

- there is no CESS in place and therefore the capex incentive may need to be strengthened, or

³⁷² NER, clause S6.2.2B(a).

³⁷³ NER, clause 6.4A(b)(3).

³⁷⁴ NER, clause S6.2.2B(b).

³⁷⁵ NER, clause S6.2.2B(c).

³⁷⁶ AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 10–12.

- a distributor's past capex performance demonstrates evidence of persistent overspending or inefficiency, thus requiring a more effective incentive.

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

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

We have chosen forecast depreciation as our default approach because, in combination with the CESS, a distributor will retain 30 per cent of an underspend or overspend, while consumers will retain 70 per cent of the underspend or overspend. This means that for a one dollar saving in capex a business gets 30 cents of the benefit while consumers get 70 cents of the benefit. For the reasons given in our capex incentive guideline, we consider this to be a sufficient incentive for a distributor to achieve efficiency gains over the regulatory control period in most circumstances.³⁷⁷ That is, the reward should not be so high that it incentivises inefficient capex deferral. This could result in consumers paying too much for the capex (since they might fund the same capex in multiple regulatory control periods). Alternatively, consumers could experience a decline in service levels. Also, the power of the incentive should be set so as to achieve balance between the incentives for capex, opex and service.

Qld distributors are not currently subject to a CESS but we propose to apply the CESS in the 2015–20 regulatory control period. That is, we propose a sharing ratio of 30 per cent to the total capex efficiency gain/loss under the CESS. We discuss this further in section 3.3. Ergon Energy supported the use of forecast depreciation given our intention to apply the CESS in the next regulatory control period.³⁷⁸ Energex accepted our proposal to apply CESS in the next regulatory control period.³⁷⁹

For Qld distributors, 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.³⁸⁰ We propose applying the CESS to both Qld distributors, as neither has demonstrated evidence of persistent overspending. Therefore, applying the criteria in our capex incentive guideline, we propose to use forecast depreciation when rolling forward to establish the RAB at the commencement of the 2020–25 regulatory control period.

³⁷⁷ AER, *Explanatory statement, capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 28–29.

³⁷⁸ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 18.

³⁷⁹ Energex, *Response to the AER's framework and approach preliminary positions*, 19 February 2014, p. 52.

³⁸⁰ Our ex post capex measures are set out in the capex incentives guideline, see AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 13–19; the guideline also sets out how all our capex incentive measures are consistent with the capex incentive objective, see AER, *Capital expenditure incentive guideline for electricity network service providers*, November 2013, pp. 20–21.

6 Jurisdictional and legacy issues

This attachment sets out our proposed approach on a range of matters raised by Ergon Energy. No such similar issue were raised by Energex. We also address dual function assets.

6.1 Ergon Energy's request

The rules do not limit the matters distributors may request the AER to amend in an F&A.³⁸¹ Similarly, we may make an F&A that extends beyond the matters specifically listed in the rules.³⁸²

In requesting that we replace the current F&A, Ergon Energy requested we address a range of matters that fall into three groups.³⁸³ The first group encompasses regulatory issues that Ergon Energy sought guidance on, but would not normally form part of the F&A. The second group includes matters related to the end of transitional regulatory arrangements that form part of the current determination. The third group involved two additional matters relating to the regulatory treatment of revenue adjustments and capital contributions.

In our preliminary positions F&A we set out our proposed approach to the matters raised by Ergon Energy.³⁸⁴ In its submission, Ergon Energy accepted our proposed approach on each of the regulatory issues.³⁸⁵ As a consequence, Ergon Energy has requested we no longer address those regulatory issues in this F&A.

Ergon Energy has noted our proposed approach on some of the transitional and revenue issues, and agreed to liaise with us on those before submitting its regulatory proposal.

Ergon Energy is seeking further clarification from us in this F&A on only four of the transitional and regulatory issues.

Below, we list each of the matters originally raised by Ergon Energy. We note how Ergon Energy now proposes to deal with each matter. We set out in appendix E a discussion of each of the issues Ergon Energy no longer wishes to be addressed in the F&A paper.

Group 1: Regulatory issues

- negotiating framework – resolved
- Mt Isa–Cloncurry network – resolved
- asset categories and asset lives – resolved
- regulatory asset base value – resolved
- no prudency review – resolved
- cost pass throughs – resolved
- application of security of supply standards – resolved.

³⁸¹ NER, clause 6.8.1(c)(1).

³⁸² NER, clause 6.8.1(g).

³⁸³ Ergon Energy, *Submission on whether it is necessary or desirable to amend or replace the current framework and approach papers*, July 2013. See appendix C for a copy of Ergon Energy's request.

³⁸⁴ AER, *Preliminary positions paper F&A for Qld*, December 2013, p. 76.

³⁸⁵ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 19.

Group 2: Transitional issues

- treatment of capital contributions in calculating the annual revenue requirement – Ergon Energy seeks a further statement on our proposed approach
- treatment of solar feed in tariffs – Ergon Energy will liaise with us
- treatment of assets included in the regulatory asset base which provide standard control, alternative control and unregulated services under transitional arrangements – Ergon Energy will liaise with us
- recovery of charges for using the Cloncurry non-regulated 220kV network – Ergon Energy seeks a further statement on our proposed approach
- recovery of entry and exit charges for non-regulated connection points with Powerlink's transmission network – Ergon Energy seeks a further statement on our proposed approach.

Group 3: Revenue issues

- revenue adjustments for the carry forward of over-recovery or under-recovery of revenue for this period – Ergon Energy will liaise with us
- our approach to capital contributions policy in the absence of NECF rule requirements – Ergon Energy seeks a further statement on our proposed approach.

6.1.1 AER's proposed approach

Below, we have summarised the approach we intend to take to each of the issues originally raised by Ergon Energy.

Group 1: Regulatory issues

- A negotiating framework is only required as part of the regulatory proposal if we indicate, as part of the F&A, that services will be classified as negotiated distribution services.
- The Mt Isa–Cloncurry network may be included in Ergon Energy's regulatory proposal.
- We will review asset categories and asset lives submitted with Ergon Energy's regulatory proposal; public lighting assets should be excluded from the regulatory asset base (RAB).
- We will consider Ergon Energy's RAB value as part of our distribution determination.
- Under transitional arrangements in the rules, we are not able to review the prudence of past capex in our determination for the next regulatory control period.
- We will make our decision on nominated pass through events as part of our distribution determination.
- In considering our distribution determination, we will again refer to the Qld Government's position on security of supply issues.

Group 2: Transitional issues

- Under the rules, distributors should exclude the value of capital contributions from their RAB. Revenue adjustments will be required in the first two years of the next regulatory control period to offset the value of forecast capital contributions for 2013–14 and 2014–15.

- We will consider treatment of solar feed-in tariffs as part of our distribution determination. We are unable to confirm which mechanism we will use to adjust Ergon Energy's revenues. In the meantime, we will liaise with Ergon Energy on this issue.
- Ergon Energy must allocate asset costs to service types according to an approved cost allocation method (CAM). We will liaise with Ergon Energy on this issue.
- Ergon Energy may include its expected costs related to the Cloncurry 220kV network and non-regulated Powerlink connections in its regulatory proposal. It is not clear that these costs should be treated as an opex step change, as proposed by Ergon Energy. We will consider this issue in our draft determination. In the meantime, we will liaise with Ergon Energy on this issue.

Group 3: Revenue issues

- We will continue to liaise with Ergon Energy on its over or under-recovery, and on how this may be managed.
- The Qld Government has announced it intends to implement NECF in 2014. However, at the time of writing, the timing of NECF implementation is uncertain. We suggest Ergon Energy develop its capital contributions policy consistent with chapter 5A of the rules (electricity connection for retail customers) and our Connection Charge Guidelines for Retail Customers.³⁸⁶ Under this approach, Ergon Energy's connections policy will be consistent with NECF, should it be implemented.

6.1.2 AER's assessment approach

We recognise the need to provide Ergon Energy with an indication of our likely approach to assist it in preparing regulatory proposals. However, we will not address in detail in the F&A matters that are:

- better addressed as part of our assessment of a distributor's regulatory proposal
- not relevant to a distributor's development of its regulatory proposal
- better addressed via normal pre-lodgement processes.³⁸⁷

6.1.3 Reasons for AER's proposed approach

In this section we set out our reasons for our proposed approach to the four issues on which Ergon Energy seeks a further statement of our approach.

Treatment of capital contributions in calculating the annual revenue requirement

Ergon Energy had requested we clarify our approach to the treatment of consumer (or capital) contributions in calculating its annual revenue requirement.³⁸⁸ Electricity consumers make capital contributions when the expected costs of connection works are larger than the expected regulated returns to the relevant distributor. For these connection projects to proceed, distributors may ask consumers to pay a capital contribution to make up the difference between expected costs and regulated revenues.

³⁸⁶ AER, *Connection charge guidelines for electricity retail customers*, June 2012.

³⁸⁷ Such as our meetings with the distributors, exchanges of emails and letters.

³⁸⁸ A service provider's annual revenue requirement is the revenue we determine it will earn in a given regulatory year from charging for standard control services.

Under transitional arrangements, in the current period the Qld distributors remain subject to the QCA's capital contributions policy.³⁸⁹ Under the QCA's approach, Ergon Energy (and Energex) added the value of forecast capital contributions into their RAB. To offset these additions, paid for by consumers, we made revenue reductions of equal value to the distributor's forecast regulated revenues. An annual overs and unders adjustment was made for any difference between the forecast and actual capital contributions. The transitional arrangements expire at the end of the current regulatory control period. With the end of the transitional arrangements, Ergon Energy's current approach to capital contributions will no longer be consistent with the regulatory framework.

For the next regulatory control period, the distributor's capital contributions policies should be consistent with the capital contributions arrangements set out in the rules.³⁹⁰ Under the rules, a distributor should exclude the value of capital contributions from its RAB.³⁹¹ In discussions with the Qld distributors, we indicated that we expect them to exclude forecast capital contributions from the RAB (consistent with other NEM jurisdictions) for the next regulatory control period.

Ergon Energy has noted our preliminary position, set out above. However, Ergon Energy seeks a further statement from us on how we will balance under or over recovery of forecast capital contributions for 2013–14 and 2014–15. Because these are the final years of the current regulatory control period, adjustments to regulated revenues will be required in the first two years of the next period. We confirm that this is the case. We have included a general term in the control mechanism formula for standard control services that makes provision for adjustments such as this. We encourage Ergon Energy to set out in its regulatory proposal the details of its proposed mechanism to address this issue. We will consider the mechanism for these adjustments in our preliminary distribution determination. We will liaise with Ergon Energy on this issue prior to it lodging its regulatory proposal.

Treatment of solar feed-in tariffs

Ergon Energy has asked us to address the treatment of its recovery of costs related to Qld's solar feed-in tariff.

Ergon Energy (and Energex) is obliged to meet the cost incurred by retailers in paying a feed-in tariff to consumers with photovoltaic cells (solar panels). This obligation is established by the Qld Government through conditions attached to the authorities under which the distributors operate.³⁹² The distributors are able to recover the cost of the feed-in tariff through their network charges. These arrangements, where the distributors in turn recover the cost from consumers, are set out in our distribution determination for the current regulatory control period.³⁹³ The distributors recover from consumers a small proportion of their annual feed-in tariff costs through an opex forecast. The distributors balance the difference between those forecasts and their actual costs through a pass through true up. The true up occurs in the second year after the year in which costs are incurred.

Our distribution determination will address the feed-in tariff costs Ergon Energy is to recover in the next regulatory control period. There are two issues in respect of the feed-in tariff for the next regulatory control period:

³⁸⁹ NER, clause 11.16.3.

³⁹⁰ NER, clause 6.21.2.

³⁹¹ NER, clause 6.21.2(1).

³⁹² An 'authority' in this case is analogous to a licence. The obligation is established by clause 44A of the *Electricity Act 1994* (Qld).

³⁹³ AER, *Queensland distribution determination 2010–11 to 2014–15*, May 2010. p. 311

- First, how will costs incurred by Ergon Energy in each year of the next regulatory control period be recovered.
- Ergon Energy has proposed a method, but does not seek a statement from us on this issue in this F&A. Rather, Ergon Energy seeks to liaise with us on its proposed approach.
- Second, how will the costs incurred by Ergon Energy in the final two years of the current regulatory control period (2013–14 and 2014–15) be recovered.
- Ergon Energy also seeks to liaise with us on an approach it has proposed to address this issue. However, Ergon Energy seeks guidance from us on the mechanism through which it would recover these costs. Specifically, would we adjust its regulated revenues by amending the building block methodology and therefore change its x-factors. Or would we adjust the control mechanism formula for its standard control services.

In response to Ergon Energy's questions, we note that any mechanism used to adjust its regulated revenues will be closely related to the approach taken to recover its 2013–14 and 2014–15 costs. We are unable to specify a mechanism to adjust Ergon Energy's revenues until we determine an approach. As Ergon Energy has agreed to liaise with us on an approach, we intend to liaise with Ergon Energy on a mechanism.

Recovery of charges for using the 220kV Cloncurry network

and

Recovery of entry and exit charges for non-regulated connection points with Powerlink's transmission network

Ergon Energy asked us to address its recovery of costs from using the non-regulated 220kV network supplying the Cloncurry Township.³⁹⁴ Also, its recovery of entry and exit charges for its four non-regulated links with Powerlink's high voltage transmission network.³⁹⁵

Ergon Energy currently recovers its costs of providing these services under transitional arrangements, whereby the QCA's approach remains applicable during the current regulatory period. Under those arrangements, Ergon Energy recovers related costs by including them in its annual pricing proposal to us.³⁹⁶ Therefore, we did not deal with these issues as part of our last distribution determination for Ergon Energy. Rather, we currently assess Ergon Energy's proposed costs for these matters annually. The costs we approve are then added to the charges levied by Ergon Energy for standard control services. Because the current transitional arrangements terminate at the end of the current regulatory period, in the next regulatory control period Ergon Energy's approach to recovering these costs should be consistent with the relevant provisions of the rules.

Under the rules, Ergon Energy may include its expected costs related to the Cloncurry 220kV network and non-regulated Powerlink connections in its regulatory proposal for the next regulatory control period.³⁹⁷ We would then consider them as part of our distribution determination process. Subject to our approval, Ergon Energy would then recover the approved costs for these matters in its charges for standard control services without us assessing them again.

³⁹⁴ Ergon Energy, *Submission on whether it is necessary or desirable to amend or replace the current framework and approach papers*, July 2013.

³⁹⁵ Entry and exit fees relate to services provided to Ergon Energy, by Powerlink, for electricity flows between the two networks.

³⁹⁶ NER, clause 11.16.9.

³⁹⁷ NER, clause 11.39.1.

Ergon Energy has now asked us to confirm that it would recover its costs for these assets as a step change in its opex allowance.³⁹⁸ As this is an issue relevant to our distribution determination, we are not able to confirm our approach until we assess Ergon Energy's proposed costs.

Capital contributions policy in the absence of NECF rule requirements

Ergon Energy has proposed to us.³⁹⁹

In the absence of National Energy Customer Framework rules applying to Ergon Energy in the next regulatory control period, we believe there may be benefit in engaging with stakeholders on how capital contributions arrangements will be applied in the next regulatory control period.

The NECF is a nationally consistent framework to regulate the retail supply and sale of electricity and gas. The framework intends to reduce regulatory costs, lower jurisdictional barriers and foster increased competition by creating a single national retail energy market. The NECF reforms incorporate standardised arrangements for new connections. These include a framework for distributors to request capital contributions from consumers.

While having cooperatively developed NECF, the decision to adopt the framework will be made by Australian states and territories individually.⁴⁰⁰ The Qld Government has announced it will implement NECF from early to mid-2014, subject to agreeing to Qld specific variations.⁴⁰¹ The Qld Government has previously indicated it sought variations to the NECF connections arrangements. However, those were in the context of an earlier plan to adopt much of NECF in 2012.⁴⁰² The proposed variations largely related to postponing the Qld implementation to coincide with the next regulatory control period for Ergon Energy and Energex—beginning in 2014.

Ergon Energy sought clarification on our approach to capital contributions should NECF not apply to it in the next regulatory control period. In our preliminary positions F&A, we noted the Qld Government's position is to implement NECF in 2014 and that we are monitoring this matter.⁴⁰³ In response, Ergon Energy continues to seek guidance on our proposed approach should NECF obligations not apply to it in the next regulatory control period.

We note that under NECF, connections will be regulated under chapter 5A of the rules and our Connection Charge Guidelines. If Ergon Energy develops its non-NECF capital contributions policy consistent with those arrangements, it will also be consistent with NECF should it apply to Ergon Energy.

6.2 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

³⁹⁸ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, p. 21.

³⁹⁹ Ergon Energy, *Submission on whether it is necessary or desirable to amend or replace the current framework and approach papers*, July 2013, p. 2.

⁴⁰⁰ South Australian legislation, including *The National Energy Retail Law (South Australia) Act 2011*, establishes the NECF reforms. To implement NECF, other states and territories must pass their own Application Act to recognise the South Australian legislation. Such enabling legislation made by other states and territories may exclude or vary elements of the South Australian legislation.

⁴⁰¹ Queensland Government, *Queensland Government response to the Interdepartmental Committee on Electricity Sector Reform*, June 2013, p. 10.

⁴⁰² Queensland Government, *National Energy Customer Framework – Queensland implementation decision paper*, March 2011, p. 6.

⁴⁰³ AER, *Preliminary positions paper F&A for Qld*, December 2013, p. 84.

consider whether we should price these assets according to the transmission or distribution pricing principles.

The treatment of dual function assets is not a feature of the current Qld distribution determination or F&A. This is because neither of the distributors owned, controlled or operated dual-function assets at the time of the last determination.

Neither Energex nor Ergon Energy currently own, control or operate any dual-function assets. This is because there is a permanent derogation in the rules in relation to the definition of 'transmission network' in Queensland.⁴⁰⁴ Therefore, we have not made any determination under the rules regarding dual function assets.⁴⁰⁵ This is consistent with our position set out in our preliminary positions F&A.

⁴⁰⁴ NER, clause 9.32.1(b).

⁴⁰⁵ NER, clauses 6.8.1(b)(1)(ii) and 6.25(b).

Appendix A – Summary of submissions to preliminary positions F&A

Respondent	Submission summary	AER response
Canegrowers	<p>Does not support our preliminary position to apply a revenue cap to standard control services. Canegrowers submitted that there is no solid evidence to show that a revenue cap is most efficient control mechanism for Qld distributors.</p> <p>Canegrowers submitted that a hybrid revenue cap which includes a proportion of controlled revenue with a set of price cap constraints to remove within period price stability.</p> <p>Does not support the wholesale application of incentive schemes to the Qld distributors. Canegrowers submitted that the schemes shield distributors from a competitive environment (e.g. not required to write down assets).</p> <p>Submitted that we should not include allowances to recover solar feed-in tariffs in the next regulatory control period. Canegrowers considers that the intent of the solar bonus scheme is non-commercial and should be paid for by the shareholder.</p> <p>Canegrowers submitted that we should use the Cost Allocation Methodology (CAM) process as an opportunity to examine the prudent costs of supply for different service types. Canegrowers further submitted that expenditures on these assets have not been prudently incurred and cannot be reasonably prescribed to a distribution service, we should remove these from the RAB. Canegrowers seeks to be involved in the development and approval of the CAM to be used by the Qld distributors.</p> <p>Canegrowers submitted that the preliminary F&A did not detail how we will regulate distributors' maximum allowed revenue (MAR). Canegrowers requested that the real cost of debt and equity be used to calculate the Qld distributors' return on assets so prices can reflect the rest cost of supply.</p>	<p>We have responded to Canegrower's submission on the control mechanism and schemes in the body of the final F&A. Further, we have considered evidence around the use of price caps in other jurisdictions. We concluded distributors have consistently over-recovered under price caps. This is not in the long term interests of consumers.</p> <p>The solar bonus scheme is not an issue for the F&A. We note the issue for the determination.</p> <p>The CAM is not an F&A issue. The CAM is not used to interrogate costs; it is a compliance measure. The NER specify that distributors must prescribe how they will allocate their costs between standard control, alternative control, negotiated distribution, non-regulated services and shared assets.</p> <p>The AER is required to assess the CAM to ensure that the CAM is in accordance with the requirements of the National Electricity Law (NEL) and NER and gives effect to and is consistent with our cost allocation guideline. The NER does not allow for an ex-post review for investments made in the current regulatory control period.</p> <p>Our rate of return guideline outlines our approach to the MAR. Its regulation will be addressed in our determination. This issue does not relate to the final F&A.</p>
Citelum	<p>Supported our preliminary position to retain public lighting as an alternative control service.</p> <p>Proposed that due to the introduction of contestability in Qld during the current period, we</p>	<p>Contestability is determined by the Qld Government, not the AER. We have no power to influence contestability of services. Public lighting is contestable in South-East Qld</p>

Respondent	Submission summary	AER response
	<p>should set a pathway to making public lighting a negotiated service beyond 2020.</p> <p>Submitted that the installation of new public lighting asset types are classified as negotiated services as most customers may seek the opportunity to explore contestability of installation and maintenance of public lighting.</p> <p>Submitted that there should not be separate charges for energy efficient lighting types—rather the cost of capital should be averaged across the number of lighting points.</p> <p>Submitted that disconnection and reconnection services for public lighting be included in our 'Table of distribution services' (insert Appendix ref) or added to large customer connections and classified as alternative control as a step towards negotiated services.</p> <p>Citelum also submitted that type 7 connection points should be made contestable or shifted from standard control to alternative control to allow for development of competition.</p>	<p>only.</p> <p>Making a service negotiated is not the same as making it contestable. Contestability can occur regardless of whether we classify the service as alternative control, negotiated or not classify the service.</p> <p>We are required, under the NER, to set cost reflective prices. Setting prices based on average lighting costs is not a cost reflective approach.</p> <p>We understand Citelum refers to information on how Councils can purchase lights. The AER does not set these prices.</p> <p>Type 7 metering services do not measure the flow of electricity. Instead, charges are calculated by distributors estimating the usage using standard data. As only distributors have the ability to accurately estimate usage, only they can bill customers. We discussed this issue in some detail in the Stage 1 F&A paper for Ausgrid, Endeavour Energy and Essential Energy.⁴⁰⁶</p>
<p>Council of the Ageing (COTA) (Qld)</p>	<p>COTA offered cautious supported for our proposed reclassification of type 5 and 6 metering services to alternative control. However, COTA is concerned that customers with more than one meter would pay for extra or multiple meters—this would be unreasonable where the customer has no control over the number or types of meters installed by a distributor. COTA suggested that as an alternative, metering charges could be allocated on the basis of a National Meter Identifier (NMI).</p> <p>COTA also flagged the number of major reforms currently underway that impact on residential customers. COTA submitted that the distributors and the AER need to be</p>	<p>COTA attended a metering workshop with the Qld distributors on the possible impacts on residential consumers.</p> <p>Our proposed approach allows for cost-reflective prices. Additionally, consumers will have a choice of provider who offers the services sought by a customer. The mechanics of how the Qld distributors move to an alternative control classification are not essential F&A questions but will be addressed in the determination. In</p>

⁴⁰⁶ AER, *Stage 1 Framework and approach paper, Ausgrid, Endeavour Energy and Essential Energy*, March 2013, p. 31.

Respondent	Submission summary	AER response
	<p>cognisant of all relevant reforms.</p>	<p>the interim, the Qld distributors should consult on the mechanics of a new approach to metering in developing their regulatory proposal.</p> <p>We acknowledge the significant reforms currently underway.</p>
<p>Department of Energy and Water Supply (Qld) (DEWS)</p>	<p>DEWS submitted that (in relation to small customer connections) the Qld Government is committed to identifying opportunities for the private sector to compete (for traditionally monopoly services) where this is effective and efficient. The optimal extent for introducing competition for small customer connection services is one area warranting further examination. DEWS is currently considering the implications of contestability in small customer connections for customers.</p> <p>DEWS supported our preliminary position to reclassify type 5 and 6 metering services as alternative control.</p> <p>Supported the Qld distributors submission to limited the incentive for STPIS to ± 2 per cent of maximum allowance revenue.</p>	<p>Noted. We are interested to receive updates from DEWS on the implications for customers should small customer connections become contestable along with any indication from the Qld Government on introducing contestability to small customer connections.</p>
<p>Far North Queensland Regional Organisation of Councils (FNQROC)</p>	<p>FNQROC submitted that WACC is currently too high.</p> <p>FNQROC also submitted that it seeks cost reflective prices for peak and off peak usage.</p> <p>FNQROC submitted that clarification of the term 'end of life' would assist it in managing its public lighting assets particularly with changes over to energy efficient luminaires.</p> <p>FNQROC sought clarification on the ability of Ergon Energy to charge a reduced rate for new/existing energy efficient luminaires with the alternative control service being able to reflect any reduced maintenance requirements.</p> <p>Submitted that Qld distributors be accountable for proposed research and development costs included in regulatory proposals. Additionally, results of research and development should be publicly available.</p>	<p>We note FNQROC's submission on WACC, however this is not an issue for the F&A.</p> <p>In relation to peak and off peak usage, the distributors introduce tariff structures that detail the nature of the tariff and the services offered. We do agree to setting an asset's 'standard life' as part of our determination. This life is used for calculating prices (the depreciation component), but that is all. The asset life we use to calculate prices imposes no obligation on the distributors to retain that asset for its full life or to replace the asset at its full life. Reduced rates for efficient luminaires is not an F&A issue. However, the question does relate to how alternative control charges are set and we have noted this issue for the determination.</p>

Respondent	Submission summary	AER response
		<p>The regulatory treatment of assets funded through grant programs will be considered as part of the determination.</p>
<p>Local Government Association of Queensland (LGAQ)</p>	<p>LGAQ has significant concerns around the implementation of contestable metering. LGAQ submitted that Energex currently requires a contestable metering agreement before a National Meter Identifier (NMI) is energised. LQAG suggested that metering for both large and small sites be under a default arrangement for the first six months so that metering issues do not hold up the process of connection of power.</p> <p>LGAQ also has significant concerns around the 'N(network) + R(retail)' approach which they submitted will result in cost increases for councils in Ergon Energy's region.</p>	<p>We note the comments raised in the submission, however they are not issues relevant to the F&A.</p> <p>Changes to retail pricing of public lighting are a Qld Government issue.</p>
<p>Origin</p>	<p>Origin supported our preliminary position to classify large customer connection and reclassify type 5 and 6 metering services as alternative control.</p> <p>Origin does not support a revenue cap for standard control services. Origin's preference is for a WAPC however a hybrid revenue cap would be acceptable. This includes a component where the revenue cap could be adjusted within period in line with key cost drivers and increasing fixed components in network price relative to volumetric components.</p> <p>Origin supported the application of CESS and EBSS in the next regulatory period.</p>	<p>We acknowledge minimising price volatility is an important issue but it is better addressed by critically reviewing future capital expenditure during the regulatory period that will form fixed costs to be recovered in future prices, irrespective of the form of control. We addressed this in further detail in the body of the F&A.</p>
<p>Queensland Consumers' Association</p>	<p>The Queensland Consumers' Association was not able to make a formal submissions, but in email correspondence to the AER on 19 February 2014, requested the following:</p> <ul style="list-style-type: none"> closely scrutinize distributor demand forecasts review adequacy of the current distribution charging zones, especially Ergon Energy's east zone, to make more cost reflective on a geographical basis, where economical to do so require more emphasis on incentive schemes for demand management, including direct load control of small customer air conditioners if not included in the Queensland Competition Authority standards, review the need for 	<p>We acknowledge these issues which are mostly relevant to the distribution determination.</p>

Respondent	Submission summary	AER response
	<p>service standards for low voltage, brownouts and other quality parameters</p> <p>ensure consumer capital contribution arrangements for all classes of consumers are fair and are being properly implemented.</p>	
Queensland Farmer's Federation (QFF)	<p>QFF are concerned about the capacity of irrigation farmers to adjust to the implementation of regulated tariffs over the next regulatory control period. QFF submitted that it is difficult to see how the approaches outlined in the preliminary positions paper will drive the implementation of efficiencies by distributors that will flow through to improved tariff outcomes.</p> <p>QFF does not consider that there will be much opportunity to open competition in metering services in rural areas in the short to medium term.</p> <p>QFF stated that it expects that the cost of improved metering will be a significant impediment to the introduction of efficient pricing structures.</p> <p>QFF supported the concept of providing incentives to improve levels of service and implement efficiencies to reduce operating and capital costs.</p>	Submission noted.
Regional Development Australia Far North Queensland and Torres Strait	Supported the AER's preliminary position on classification of services, control mechanisms and application of incentive schemes.	Submission noted.
Simply Energy	<p>Supported our proposed reclassification of type 5 and 6 metering services to alternative control.</p> <p>Simply Energy sought an explanation on how exit fees are payable for the removal of a distributor owned meter.</p> <p>Supported our preliminary position to apply a revenue cap including tolerance limits that smooths overs and unders.</p> <p>Noted that Energex recently contacted Simply Energy seeking views on how they recover lost revenue from households or businesses by-passing the meter. Simply Energy is concerned that Energex may already recover lost revenue through distribution loss factors. If</p>	<p>We note the submission on exit fees however we will address this issue as part of our determination. In the interim, the Qld distributors should consult on the mechanics of how they propose to roll-out metering, including exit fees, in developing their regulatory proposal.</p> <p>We acknowledge the issue of lost revenue from theft. However, this issue will be considered in the determination. Additionally, there are some provisions of the National Energy Retail Rules that allow retailers and distributors manage risk of loss through theft that may be</p>

Respondent	Submission summary	AER response
	not, Simply Energy submitted that Energex should be allowed to recover this lost revenue through their revenue cap.	relevant to Energex's proposed allocation of that risk.
Vector	<p>Vector supported our proposed reclassification of type 5 and 6 metering services as alternative control services. They submitted that a user pays approach improves transparency and reduces the risk of cross-subsidisation.</p> <p>Vector noted that we were silent in our preliminary F&A on the financial treatment of newly classified metering services, including how assets will be depreciated.</p>	We acknowledge that the rate of depreciation of the metering asset base is an important issue, which we will consider in the determination. We are looking to the Qld distributors to engage with stakeholders on metering, including options around the financial treatment of these assets before submitting their regulatory proposals.
<p>The following section sets out submissions from Energex and Ergon Energy that were not addressed in the body of the document, our proposed classification of Qld distributors' distribution services at appendix B, or response to Ergon Energy's table of services at appendix D.</p>		
Energex	For public lighting services, Energex submitted a continuation of the current price cap control mechanism. Energex proposes that this approach would also be applied to type 5 and 6 metering services classified as alternative control services (assuming these services are classified this way).	Agreed.
Energex	Requested that we limit any revenue at risk for the telephone answering parameter (as part of the STPIS) to ± 0.1 per cent. Energex argued that it is not prudent that the revenue at risk be set at the maximum of ± 0.5 per cent per year, as the amount of expenditure dedicated to the contact centre is insignificant compared to the total opex allowance to warrant large revenue exposure.	We will make our determination on the revenue at risk at the determination. We have proposed a total revenue at risk at ± 2 per cent under the STPIS. This is a proposed approach only.
Ergon Energy	Ergon Energy's submission states 'we also note that the AER intends to consult with consumers on the treatment of confidential information' (at page 4).	We are currently unaware of what information Ergon Energy will claim as confidential. Hence, we are unable to consult with consumers on the treatment of confidential information. We expect that Ergon Energy will consult broadly on information it claims as confidential, particularly with consumer representatives, and seek to resolve any disagreements prior to

Respondent	Submission summary	AER response
		submitting its regulatory proposal.
Ergon Energy	Submitted that 'we should provide early indication of the basis of control to enable Ergon Energy to prepare indicative prices...if the AER does not provide its preferred approach in the F&A, and to the extent that a distributor has complied with the F&A in respect of the control mechanism outlined, the AER should not be able to reject our approach to arriving at the variables consistent with the formula' (see page 10 of submission).	The rules do not require us to set out basis of control.
Ergon Energy	Submitted that a limited building block approach should apply to type 5 and 6 meter provision, maintenance, reading and data services as well as the provision, construction and maintenance of public lighting (except removal/relocation of public lighting assets).	If Ergon Energy wishes to propose this approach in its regulatory proposal, we expect it would consult on the implications to consumers which would be set out in their proposal.
Ergon Energy	Submitted that the control mechanism formula that applies to large customer connections should include a commercial profit margin. Ergon Energy states that 'the inclusion of a profit margin would minimise any concern that the AER's controls on revenue and pricing create a barrier for potential market entrants in the design and construction of large customer connections'. Alternatively, Ergon Energy says we should consider an 'unregulated classification'.	We will not include a commercial profit margin for large customer connections. We are required to only approve the efficient costs of services. Our reasons for retaining an alternative control classification for large customer connections is set out in the body of the F&A.
Ergon Energy	Ergon Energy submitted its support for 'a continuation of the current control mechanism formula for services that are fee based (subject to any minor amendments made in our Regulatory Proposal)'.	The rules (at clause 6.12.3(c1)) provide that the formulae that give effect to the control mechanism must be as set out in the F&A unless we consider that unforeseen circumstances justify departing from the formulae set out in that F&A.

Appendix B – Classification of Qld distributors' distribution services

Service group	Further description (if any)	AER classification 2015–20	Current classification 2010–15
AER Service group— Network services			
Planning the network	<p>Network asset - assessment of asset requirements involving investment, management and delivery including risk and feasibility assessment and estimating and cost planning.</p> <p>Demand management - the identification and development of non-network options to address forecast network limitations.</p> <p>Network forecasting - analysis of network demand to enable the development of the capital program of works.</p> <p>Network business strategy development - strategic initiatives development and management including business improvement/efficiency initiatives.</p> <p>Governance - developing policies, procedures and standards.</p> <p>Regulatory planning as required by the National Electricity Rules (rules).</p>	Standard control	Standard control
Designing the network	<p>Creation of a plan or the standards and criteria for network construction. Includes developing design standards, protection engineering and designs for augmentation and extensions to the shared network.⁴⁰⁷</p>	Standard control	Standard control

⁴⁰⁷ Excluding designs for augmentation and extensions to shared network undertaken in feasibility and concept scoping for large customer connections (i.e. prior to acceptance of connection offer)

Service group	Further description (if any)	AER classification 2015–20	Current classification 2010–15
Constructing the network	<p>Network construction, augmenting the shared network and extensions of shared network.</p> <p>Project planning and works management (works program development, procurement, vendor management, contract management, work scheduling and dispatching).</p> <p>Management of environmental issues.</p> <p>Asset deployment and commissioning of shared network assets.</p> <p>Asset relocation (other than those undertaken at a customer's request).</p> <p>Installing network related load control on customer premises.</p>	Standard control	Standard control
Maintaining the network	<p>Planned maintenance – activities carried out to reduce the probability of failure or performance degradation of a network asset.</p> <p>Corrective – activities undertaken to detect, isolate and rectify a fault so that the failed equipment, machine or system can be restored to normal operable state.</p> <p>Work to restore a failed component of the distribution system to an operational state.</p> <p>Maintaining network related load control devices on customer premises.</p>	Standard control	Standard control
Operating the network	<p>Network control and operation.</p> <p>Outage management.</p> <p>Emergency management and response.</p> <p>Field operations.</p> <p>Switching and testing for network purposes.</p> <p>Scheduling and controlling the switching of controllable load for network purposes.</p> <p>Operation of load control devices on customer premises.</p>	Standard control	Standard control
Administrative support for provision of network services	<p>Customer interactions including network product development, customer service management/call centre, complaints and enquiries, record management and network claim processing.</p> <p>Market operations: includes revenue management, network billing, processing of service</p>	Standard control	Standard control

Service group	Further description (if any)	AER classification 2015–20	Current classification 2010–15
	<p>order requests, and market notifications of retailer changes.</p> <p>National Metering Identifier (NMI) establishment, discovery requests and classification in accordance with the rules.</p> <p>Populate and maintain NMI standing data in Market Settlement and Transfer Solution in accordance with the rules.</p> <p>Processing and publication of notifications of new connections and alterations.</p> <p>Pricing strategy and development of pricing proposals.</p> <p>Financial and commercial management.</p> <p>Compliance monitoring and reporting.</p> <p>Procurement activities.</p> <p>Technical and safety training of distributor staff.</p> <p>Supply, manage and maintain distributor Fleet.</p> <p>Retailer management (e.g. credit support).</p> <p>Administration of connections pioneer / rebate scheme.</p> <p>Supply, manage, test and maintain field equipment (other than metering equipment).</p> <p>Responding to cold water reports.</p> <p>Network claim processing where distributor is at fault.</p> <p>External stakeholder interactions (regulatory, government and industry).</p> <p>Environmental health and safety management (risk assessment, monitoring, program management, reporting and training).</p>		
AER service group—pre-connection services			
General connection enquiry services	<p>Provision of standard information and general advice during connection enquiry. Includes, but is not limited to:</p> <ul style="list-style-type: none"> ▪ provision of general connection information (e.g. supply availability) ▪ advice on process, such as how to complete a connection application 	Standard control	Standard control

Service group	Further description (if any)	AER classification 2015–20	Current classification 2010–15
	<ul style="list-style-type: none"> ▪ and services associated with an initial assessment of a connection applicant’s enquiry and provision of a response. 		
Connection application services	<p>Services associated with assessing a connection application, making a connection offer and negotiating offer acceptance. Unless otherwise specified, services or activities undertaken under this service group relate to both small and large customers and real estate development connections. Includes, but is not limited to:</p> <ul style="list-style-type: none"> ▪ Application services to assess connection application and making of compliant connection offer. ▪ Undertaking design for small customer or real estate development connection offer (excludes detailed design undertaken after a connection offer has been accepted). ▪ Carrying out planning studies and analysis relating to connection applications. ▪ Feasibility and concept scoping, including planning and design, for large customer connections. ▪ Negotiation services involved in negotiating a connection agreement. ▪ Tender process – distributor may carry out tender process on behalf of connection applicant or distributor may assist connection application. ▪ Protection and Power Quality assessment prior to connection. 	Alternative control	Alternative control
Pre-connection consultation services	<p>Additional support services provided by the distributor (on request) during connection enquiry and connection application other than General Connection Enquiry Services and Connection Application Services. Generally relates to services which require a customised or site-specific response and/or are available contestably. Unless otherwise specified, services or activities undertaken under this service group relate to both small and large customers and real estate development connections. Includes:</p> <ul style="list-style-type: none"> ▪ site inspection in order to determine nature of connection ▪ provision of site-specific connection information and advice for small or large customer 	Alternative control	Alternative control

Service group	Further description (if any)	AER classification 2015–20	Current classification 2010–15
	<p>connections</p> <ul style="list-style-type: none"> preparation of preliminary designs and planning reports for small or large customer connections, including project scopes and estimates customer build, own and operate consultation services. 		
AER service group—connection services			
Small customer connections ⁴⁰⁸	<p>Design, construction, commissioning and energisation of connection assets for small customers.</p> <p>(Generally, small customers are those customers who connect under the Standard Asset Connection tariff class in the distributor's pricing proposal.⁴⁰⁹)</p>	Standard control	Standard control
Large customer connections ⁴¹⁰	<p>Design and construction of connection assets for large customers.⁴¹¹</p> <p>Generally, large customers are those customers who connect under the Individually Calculated Customer (ICC), Connection Asset Customer (CAC) and Embedded Generator (EG) tariff classes as per the distributor's pricing proposal.</p> <p>We consider that connection of embedded generators larger than 30 kVA but smaller than 1 MW should be treated as large customer connections.</p>	Alternative control	Alternative control
Commissioning and energisation of large customer connections	<p>Commissioning and energisation of large customer connection assets to allow conveyance of electricity. Inspection and testing of connection assets.</p> <p>Includes administration services involved in reconciling the financials of a connection project, processing and finalising network information and contracts in relation to a connection.</p> <p>Includes generation required to supply existing customers while equipment is de-energised to allow testing and commissioning of large customer connection assets.</p>	Alternative control	Standard control

⁴⁰⁸ Ergon Energy uses 'minor customer' in place of 'small customer'.

⁴⁰⁹ See the Energex and Ergon Energy tariff schedules, available at their websites: www.energex.com.au and www.ergon.com.au

⁴¹⁰ Ergon Energy uses 'major customer' in place of 'large customer'.

⁴¹¹ Does not include augmentation of the existing network.

Service group	Further description (if any)	AER classification 2015–20	Current classification 2010–15
Real estate development connection	Design, construction, commissioning and energisation of connection assets for real estate developments.	Alternative control	Standard control
Removal of network constraint for embedded generator	Augmenting the network to remove a constraint faced by an embedded generator. (Generally, 'embedded generators' are those customers who connect under the Embedded Generator (EG) tariff class as per the distributor's pricing proposal. This does not include customers with micro-generation facilities that connect under a Standard Asset Customer (SAC) tariff class. We consider that generators larger than 30 kVA but smaller than 1 MW should be treated as embedded generators for the purpose of removing network constraints.)	Alternative control	Standard control
Temporary connections	Customer requests a temporary connection for short term supply (e.g. blood bank vans, school fetes).	Alternative control	Alternative control
AER service group—post connection services			
Operate and maintain connection assets	Works to operate, maintain, repair and replace connection assets owned by or gifted to the distributor to a technically acceptable standard. Excludes works initiated by a customer, which is not required for the efficient management of the network or for distributor purposes (such as customer requests to provide or maintain connection assets to a higher standard).	Standard control	Standard control
Connection management services (post connection)	Work initiated by a customer which is specific to a connection point. Includes, but is not limited to: <ul style="list-style-type: none"> ▪ Supply abolishment. ▪ Move point of attachment. ▪ Re-arrange connection assets at customer's request. ▪ Overhead service line replacement – customer requests the existing overhead service to be replaced (e.g. as a result of a point of attachment relocation). No material change to load. ▪ Auditing services – auditing of connection assets after energisation to network. ▪ Protection and power quality assessment - (e.g. embedded generation connected to 	Alternative control	Alternative control

Service group	Further description (if any)	AER classification 2015–20	Current classification 2010–15
	<p>network).</p> <ul style="list-style-type: none"> ▪ Customer requested works to allow customer or contractor to work close. ▪ Temporary disconnections and reconnection (including de-energisations and re-energisations) which may involve a line drop. e.g. community events. ▪ Supply enhancement. e.g. upgrade from single phase to three phase. ▪ Provision of connection services above minimum requirements – customer requests increase in reliability or quality of supply beyond the standard, and/or above minimum regulatory requirements (e.g. reserve feeder). ▪ Upgrade from overhead to underground service. ▪ Customer consultation or appointment (if requested on B2B service order). ▪ Rectification of illegal connections or damage to overhead or underground service cables. ▪ De-energisation: <ul style="list-style-type: none"> ▪ Retailer requests de-energisation of the customer's premises (business or after hours) where the de-energisation can be performed (e.g. pole, pillar or meter isolation link). ▪ Retailer requests de-energisation of the customer's premises – Main switch seal (business or after hours). ▪ Re-energisation: <ul style="list-style-type: none"> ▪ Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account (business or after hours). ▪ Retailer requests a re-energisation of the customer's premises following a main switch seal (business or after hours). 		

Service group	Further description (if any)	AER classification 2015–20	Current classification 2010–15
	<ul style="list-style-type: none"> ▪ Reading provided for an active site. ▪ Retailer requests a re-energisation of the customer's premises after a physical disconnection and premises requires a visual examination. 		
<p>Accreditation of alternative service providers and approval of their designs, works and materials</p>	<p>Accreditation of service providers that meet competency criteria.</p> <p>Approval of third party design, works and materials:</p> <ul style="list-style-type: none"> ▪ Review, Inspection and Auditing of design and works carried out by an alternative service provider prior to energisation. ▪ Certification of non-approved materials – approval of non-approved materials to be used on the network. 	Alternative control	Standard control
AER Service group— Metering services			
<p>Type 5 and 6 metering installation, provision, maintenance, reading and data services</p>	<p>On site connection of a new meter at a customer's premises, and on site connection of an upgraded meter at a customer's premises where the customer initiates the upgrade.</p> <p>Meter provision refers to meter selection, procurement, programming, testing and management of NMI standing data according to the rules.</p> <p>Meter maintenance covers scheduled maintenance, meter inspection, removal of meter and meter tampering.</p> <p>Meter reading refers to quarterly or other regular reading of a meter.</p> <p>Metering data services include collection, processing, storage and delivery of metering data, remote or self-reading at difficult to access sites, provision of metering data from previous 2 years, ongoing provision of metering data.</p> <p>Meter Data Services provided as part of general obligations as a local network service provider in accordance with the rules.</p>	Alternative control	Standard control

Service group	Further description (if any)	AER classification 2015–20	Current classification 2010–15
Type 7 metering services	Administration and management of type 7 metering installations in accordance with the Rules and jurisdictional requirements. Includes the processing and delivery of calculated metering data for unmetered loads, and the population and maintenance of load tables, inventory tables and on/off tables.	Standard control	Standard control
Auxiliary metering services	<p>Off-cycle meter read, including:</p> <ul style="list-style-type: none"> ▪ special meter reads ▪ move in move out meter reads ▪ check read – check the accuracy of the meter reading. <p>Testing for type 5 and 6 metering installations - customer requested meter accuracy testing.</p> <p>Meter inspection and investigation – a request to conduct a site review of the state of the customer’s metering installation without physically testing the metering equipment.</p> <p>Alterations and additions to current metering equipment, includes:</p> <ul style="list-style-type: none"> ▪ meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment ▪ exchange meter – customer requests exchange of their current meter (e.g. for alternative metering configuration/consolidation of multiple meters for one meter), or customer requests exchange of their current meter for a solar PV meter. <p>Provision, installation, testing and maintenance of instrument transformers for metering purposes.</p> <p>Type 5 to 7 non-standard metering services.</p> <p>Replacement or removal of a type 5 or 6 meter instigated by a customer switching to a non-type 5 or 6 meter that is not covered by any other fee.</p> <p>Meter re-seal – where the customer has caused the meter to need re-sealing (e.g. by</p>	Alternative control	Alternative control

Service group	Further description (if any)	AER classification 2015–20	Current classification 2010–15
	<p>having electrical work done on site).</p> <p>Install additional metering.</p> <p>Reconfigure meter.</p> <p>Meter exit fee – recovery of stranded asset costs associated with the removal of a meter(s) from customer's premises before the end of its useful life at the request of the customer (or customer's retailer) due to a change in Responsible Person / Meter Coordinator.</p> <p>Install metering related load control.</p> <p>Remove load control relay or time clock.</p> <p>Change load control relay channel at retailer, customer or other third party request, that is not a part of initial load control installation, nor part of standard asset maintenance or replacement.</p>		

AER Service group— Ancillary network services

<p>Services provided in relation to a Retailer of Last Resort (ROLR) event</p>	<p>Distributors may be required to perform a number of services as a distributor when a ROLR event occurs. These include:</p> <p>Preparing lists of affected sites, and reconciling data with Australian Energy Market Operator listings; handling in-flight transfers; identifying open service orders raised by the failed retailer and determining actions to be taken in relation to those service orders; arranging estimate reads for the date of the ROLR event and providing data for final NUOS bills in relation to affected customers; preparing final invoices for NUOS and miscellaneous charges for affected customers; preparing final debt statements; extracting customer data, providing it to the ROLR and handling subsequent enquiries; handling adjustments that arise from the use of estimate reads; assisting the retailer with the provision of network tariffs to be applied and the customer move in process; administration of any 'ROLR cost recovery scheme distributor payment determination'.</p>	<p>Alternative control</p>	<p>Not currently classified</p>
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Service group	Further description (if any)	AER classification 2015–20	Current classification 2010–15
Other recoverable works	<p>Works initiated by a customer, which are not covered by another service and are not required for the efficient management of the network, or to satisfy distributor purposes or obligations. Includes:</p> <ul style="list-style-type: none"> ▪ Customer requests provision of electricity network data requiring customised investigation, analysis or technical input (e.g. requests for pole assess information and zone substation data). ▪ Bundling of cables carried out at the request of another party. ▪ Provision of services, other than standard connection, for approved unmetered equipment, public telephones, traffic lights and public BBQs. ▪ Customer requested appointments. ▪ Attendance at customer's premises to perform a statutory right where access is prevented. ▪ Rearrangement of network assets (other than connection assets). ▪ Conversion to aerial bundled cables. ▪ Aerial markers. ▪ Installation of covers on service lines (tiger tails). ▪ Assessment of parallel generator applications. ▪ Witness testing. 	Alternative control	Alternative control
AER Service group—Public lighting services			
Provision, construction and maintenance of public lighting.	<p>Application assessment, design, review and audit public lighting services.</p> <p>Provision, construction and maintenance of new street lighting services.</p>	Alternative control	Alternative control

Service group	Further description (if any)	AER classification 2015–20	Current classification 2010–15
	<p>Alteration, repair, relocation, rearrangement or removal of existing street light assets and energy efficient retrofit.</p> <p>Provision of glare shields, vandal guards, luminaire replacement with aero screens.</p> <p>A fee for the residual asset value of non-contributed public lights when removed from service before the end of their useful life at the request of the customer.</p> <p>Operating street lighting assets including handling enquiries and complaints and dispatching crews to repair assets.</p>		
Emerging public lighting technology.	<p>New public lighting technologies, including trials.</p> <p>Energy efficient retrofit (including where customer requests to retrofit existing assets before end of life).</p>	Alternative control	Unclassified
Unclassified distribution services			
Emergency recoverable works	Work to repair damage to the distribution network caused by an identifiable third party from whom costs may be recovered.	Unclassified	Alternative control
Type 1 to 4 metering	Contestable metering services.	Unclassified	Unclassified
Watchman	Unmetered light mounted on customer's property or distribution pole for security purposes.	Unclassified	Unclassified
Distribution services provided in unregulated isolated networks	Ownership and operation of isolated supply networks, other than the Mt Isa-Cloncurry supply network (Ergon Energy).	Unclassified	Unclassified
High load escorts	Request by customer to scope an appropriate route and lift wires to allow passage of high vehicles.	Unclassified	Alternative control / Unclassified

Service group	Further description (if any)	AER classification 2015–20	Current classification 2010–15
Non-distribution services that are unregulated⁴¹²			
Rental and hire services	Rental of distributor owned property (e.g. plant hire and asset leasing).	Unregulated	Unregulated
Test, inspect and calibrate	Calibration and testing of equipment for external party products.	Unregulated	Unregulated
Property services	Customers request the distributors undertake conveyancing property searches, conduct easement negotiations or purchase negotiations.	Unregulated	Unregulated
Contracting services to other network service providers	Services, such as specialist cable jointers, provided to other network service providers.	Unregulated	Unregulated
Provision of training to external parties	Specialist post and pre-trade training provided by distributors to external parties.	Unregulated	Unregulated
Equipment services	<p>Safety testing of equipment such as:</p> <ul style="list-style-type: none"> ▪ insulating gloves ▪ live line hot sticks and rubber products ▪ insulating mats and covers ▪ voltage and phasing detectors, operational sticks ▪ harnesses, climbing kits, rescue kits ▪ step/extension ladders, pole platforms. 	Unregulated	Unregulated

⁴¹² In addition to services listed here, the distributors may use regulated assets to provide a range of unregulated services. Such assets are referred to by the rules as 'shared assets' and are subject to a revenue sharing mechanism set out in the AER's Shared Asset Guideline, available at www.aer.gov.au.

Service group	Further description (if any)	AER classification 2015–20	Current classification 2010–15
Sale of inventory, asset or scrap		Unregulated	Unregulated
Operate and maintain customer assets	Contract to provide, operate and maintain services for connection assets owned by customer.	Unregulated	Unregulated

Appendix C – Rule requirements for classification

We must have regard to four factors when classifying distribution services.⁴¹³

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.⁴¹⁴
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)⁴¹⁵
3. the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction)⁴¹⁶
4. any other relevant factor.⁴¹⁷

The rules specify additional requirements for services we have regulated before.⁴¹⁸ They are:

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

⁴¹³ NER, clause 6.2.1(c).

⁴¹⁴ NEL, s. 2F.

⁴¹⁵ NER, clause 6.2.1(c)(2).

⁴¹⁶ NER, clause 6.2.1(c)(3).

⁴¹⁷ NER, clause 6.2.1(c).

⁴¹⁸ NER, clause 6.2.1(d).

We must have regard to six factors when classifying direct control services as either standard control or alternative control services.⁴¹⁹

1. the potential for development of competition in the relevant market and how the classification might influence that potential
2. the possible effects of the classification on administrative costs of us, the distributor and users or potential users
3. the regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made
4. the desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction)
5. the extent that costs of providing the relevant service are directly attributable to the customer to whom the service is provided, and
6. any other relevant factor.⁴²⁰

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.

⁴¹⁹ NER, clause 6.2.2(c).

⁴²⁰ NER, clause 6.2.2(c).

Appendix D – AER response to Ergon Energy classification comments⁴²¹

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
AER service group—network services					
Planning the network	Network asset – assessment of asset requirements involving investment, management and delivery including risk and feasibility assessment and estimating and cost planning	Standard control	Standard control	Ergon Energy requests that a more generic description and definition be applied, so that there are no perverse outcomes if a particular function or cost is inadvertently omitted from the AER's classification table. Ergon Energy also prefers the more high level definitional approach the AER has adopted for 'Network Services' in its Preliminary Positions Framework and Approach Paper for South Australia.	We have addressed Ergon Energy's proposal on high level classifications in attachment 1.
	Demand management - the identification and development of non-network options to address forecast network limitations.			Ergon Energy seeks clarification on the AER's expectations around who should fund any planning work on the shared network in feasibility and concept scoping phases in the case of large customer connections.	We agree with Ergon Energy's proposal that the distributors should be able to charge a large customer for shared network planning and design works incurred before it accepts a connection offer. Allowing distributors to charge for planning and design works incurred before an agreement is reached is consistent with the cost of large customer connections being charged to individual large customers.
	Network forecasting – analysis of network demand to enable the development of the capital program of works			In our view, any planning and design on the shared network in feasibility and concept scoping phases should be an Alternative Control Service. That is, the DNSP should only fund planning and design work on the shared network once a large customer connection applicant has committed to connection works and there has been acceptance of the connection offer.	To give effect to our classification decision, we have incorporated 'feasibility and concept scoping, including planning and design' in the alternative control service 'connection
	Network business strategy development - strategic initiatives development and management including business improvement/efficiency initiatives			If all planning and design on the shared network is to be a Standard Control Service, all customers will fund the cost of plans that do not	
	Governance - developing policies, procedures and standards				

⁴²¹ Ergon Energy submitted, in tabular form, detailed comments on the classifications table we published with our preliminary positions paper F&A for Qld. These were in addition to its high level comments provided in the body of its submission. In this appendix, we respond to each of Ergon Energy's comments provided in tabular form. We note Energex also provided a much smaller number of comments in tabular form in its submission. We consider we have dealt with the issues raised by Energex in attachment 1 of this F&A. Therefore, we have not provided a separate table of responses to Energex's detailed comments.

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
	Regulatory planning as required by the National Electricity Rules			go ahead, as well as those costs which can be directly attributed to a specific large customer connection application.	application services' under connection services.
Designing the network	Creation of a plan or the standards and criteria for network construction. Includes developing design standards, protection engineering and designs for augmentation and extensions to the shared network.	Standard control	Standard control	As above, Ergon Energy seeks clarification on the AER's expectations around who should fund any design work on the shared network in feasibility and concept scoping phases in the case of large customer connections. In our view, these services should be classified as an Alternative Control Service, and form part of the services provided to large customers under the proposed 'Pre-connection services' service group.	As above.
Constructing the network	<p>Network construction, augmenting the shared network and extensions of shared network.</p> <p>Project planning and works management (works program development, procurement, vendor management, contract management, work scheduling and dispatching)</p> <p>Management of environmental issues</p> <p>Asset deployment and commissioning of shared network assets</p> <p>Asset relocation (other than those undertaken at a customer's request)</p> <p>Installing network related load control devices on customer premises⁴²²</p>	Standard control	Standard control	<p>Ergon Energy has experienced some issues in the current period with splitting up works associated with a large customer connection into Standard Control and Alternative Control Services.</p> <p>The AER could consider an Alternative Control Service classification for augmenting and extending the shared network, where this is directly attributable to facilitating a large customer connection. This would be in line with the AER's proposed approach to Embedded Generators (EGs) (i.e. removal of network constraints). This will effectively mean that all major customers will pay for deep augmentation that is attributable to their connection and any costs associated with extending the shared</p>	Works to augment the existing network (as opposed to extending the network to a new customer) in relation to a new customer connection are generally treated as shared costs because such augmentation typically benefits more than one identifiable customer. However, we do not wish to preclude the possibility of a customer contributing to augmentation required because of its new connection. We are open to establishing an alternative control service for augmentation of the existing network that is required because of a new large customer connection. There is a barrier to our adoption of such an approach at this time. At this point,

⁴²² Highlighted text represents changes in response Ergon Energy's table of detailed classification comments.

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
				<p>network (i.e. in addition to any costs associated with construction of their connection assets).</p> <p>If adopted, the DNSP would then develop high level principles on when the costs would be payable. These principles could be approved by the AER as part of the connection policy (if NECF applies).</p>	<p>without detailed arrangements for identifying when network augmentation costs could be directed to a newly connecting large customer, we are unable to see how such a mechanism would work.</p> <p>We invite Ergon Energy and Energex to set out such details in their connections policies. We expect that each distributor will submit connections policies to us with their regulatory proposal. At that time we may consider the submitted details to have been unforeseeable.⁴²³</p> <p>We would then consider making adjustments in our draft determination to create a new alternative control service for network augmentation related to a large customer connection.</p>
Maintaining the network	<p>Planned maintenance – activities carried out to reduce the probability of failure or performance degradation of a network asset</p> <p>Corrective – activities undertaken to detect, isolate and rectify a fault so that the failed equipment, machine or system can be restored to normal operable state</p> <p>Work to restore a failed component of the distribution system to an operational state</p>	Standard control	Standard control	Ergon Energy requests that a more generic description and definition be applied, so that there are no perverse outcomes if a particular function or cost is inadvertently omitted from the AER’s classification table.	We have addressed Ergon Energy’s proposal on high level classifications in attachment 1.

⁴²³ Under the rules, the service classifications we publish with this F&A may only be amended by our draft or final determinations in response to unforeseen circumstances.

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
	Maintaining network related load control devices on customer premises				
Operating the network	<p>Network control and operation</p> <p>Outage management</p> <p>Emergency management and response</p> <p>Field operations</p> <p>Switching and testing for network purposes</p> <p>Scheduling and controlling the switching of controllable load for network purposes</p> <p>Operation of network related load control devices on customer premises</p>	Standard control	Standard control	<p>Ergon Energy requests that a more generic description and definition be applied, so that there are no perverse outcomes if a particular function or cost is inadvertently omitted from the AER's classification table.</p> <p>Ergon Energy also notes that costs associated with load control should only apply to Alternative Control Services to the extent they relate to the actual meter. The provision of the load control equipment that is separate to the meter and necessary for safe, secure and reliable operation of the network should be a 'Network Service', and therefore a Standard Control Service.</p>	<p>We have addressed Ergon Energy's proposal on high level classifications in attachment 1.</p> <p>We agree load control equipment not related to the meter should be considered network services and therefore classified standard control. We have added network related load control to service groups for constructing, maintaining and operating the network. We discuss network related load control in more detail in attachment 1.</p>
Administrative support for provision of network services	<p>Customer interactions including network product development, customer service management/call centre, complaints and enquiries, record management and network claim processing.</p> <p>Market operations: includes revenue management, network billing, processing of service order requests, and market notifications of retailer changes.</p> <p>National Metering Identifier (NMI) establishment, discovery requests and classification in accordance with the rules.</p> <p>Populate and maintain NMI standing data in Market</p>	Standard control	Standard control	<p>Since the classification of services will apply to both Energex and Ergon Energy, it is important to ensure that the descriptions do not refer to specific distributors. Ergon Energy believes that 'Energex' should be removed from the following:</p> <p>"Supply, manage, test and maintain Energex field equipment (other than metering equipment)".</p> <p>Ergon Energy considers there needs to be more definitive boundaries around the scope of 'Market Operations', and in particular what costs</p>	<p>We have removed 'Energex' from the service group definition.</p> <p>It is not unusual for network service providers such as Ergon Energy to operate systems supporting more than one service category. The purpose of the rules' cost allocation provisions is to have such shared costs allocated to service categories appropriately, reflecting resource use to provide different types of services. The cost of</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
	<p>Settlement and Transfer Solution in accordance with the rules.</p> <p>Processing and publication of notifications of new connections and alterations.</p> <p>Pricing strategy and development of pricing proposals.</p> <p>Financial and commercial management</p> <p>Compliance monitoring and reporting.</p> <p>Procurement activities.</p> <p>Technical and safety training of DNSP staff.</p> <p>Supply, manage and maintain DNSP Fleet.</p> <p>Retailer management (e.g. credit support).</p> <p>Administration of connections pioneer / rebate scheme.</p> <p>Supply, manage, test and maintain Energex[delete] field equipment (other than metering equipment).</p> <p>Responding to cold water reports.</p> <p>Network claim processing where distributor is at fault.</p> <p>External stakeholder interactions (regulatory, government and industry).</p> <p>Environmental health and safety management (risk assessment, monitoring, program management, reporting and training).</p>			<p>associated with network billing should be recovered through Standard Control Services. It should be noted that a number of systems and resources utilised by Ergon Energy for network billing purposes have a dual purpose, and are also utilised for metering related functions and obligations (now proposed to be classified as an Alternative Control Service).</p> <p>Ergon Energy also incurs a range of costs associated with services provided as part of our general obligations as a Local Network Service Provider. These costs are incurred even if Ergon Energy is not the Metering Provider (MP) or Responsible Person (RP) under the NER (as is the case for Type 1 to 4 meter service provision). The AER's classification must ensure such services are classified as a Standard Control Service within the 'Network Services' grouping. This is because it is more appropriate to recover such costs from all customers, instead of recovering these costs from a specific sub-set of customers that may pay Alternative Control Service metering charges to Ergon Energy. We are also of the view that a number of other services currently listed within the 'Metering Services' grouping are more appropriately classified as Standard Control network services, and should not form part of the costs recovered through Alternative Control Service charges. Ergon Energy's reasons for this are discussed in the 'Metering Services' section below.</p> <p>Finally, Ergon Energy seeks clarification from the AER on whether they are intending to create an exhaustive list under this service grouping, and</p>	<p>systems supporting multiple categories of services should be allocated between service categories using Ergon Energy's approved Cost Allocation Method (CAM).</p> <p>We note Ergon Energy is revising its CAM. We expect to receive Ergon Energy's amended CAM to consider for approval prior to Ergon Energy submitting its regulatory proposal.</p> <p>The issue Ergon Energy raised here about costs it 'incurred even if Ergon Energy is not the Metering Provider (MP) or Responsible Person (RP) under the NER' was also raised by Ergon Energy in its comments on service group 'Type 5 and 6 metering provision, maintenance, reading and data services'. We have responded to this issue against those comments.</p> <p>We do not agree our classification decisions rely on services being provided by Ergon Energy as part of its 'general obligations'. The rules set out a range of factors we must have regard to in classifying services.</p> <p>We do not intend to establish exhaustive lists in our service group descriptions. Rather, we aim to provide sufficient detail and examples to make clear our intended classification approach. Where necessary for clarity, our service group descriptions include activities</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
				<p>whether it is the AER's intention to capture activities which may not be directly correlated to a 'service' that is actually provided or utilised by customers.</p> <p>As currently drafted, it appears this list is not exhaustive, and encompasses examples of direct costs and support costs which a DNSP may incur, which are not necessarily directly attributable to services delivered to our customers. For example, Ergon Energy does not offer compliance monitoring and reporting, financial and commercial management or pricing strategy to customers.</p> <p>While these are necessary functions and costs that Ergon Energy has in our role as a monopoly service provider, they are not 'services' which necessarily need a classification in order to identify how associated costs are to be recovered under a revenue and pricing control regime.</p> <p>If such functions and costs are to be captured within the classification of services, Ergon Energy requests that a more generic description and definition be applied, so that there are no perverse outcomes if a particular function or cost is inadvertently omitted from the AER's classification table. That is, if a cost or function is clearly necessary in our role as a monopoly service provider, and an Alternative Control Service arrangement is clearly not appropriate (i.e. costs need to be shared by all customers), then Ergon Energy should not be restricted from proposing to recover such costs as part of our revenues for Standard Control Services, simply</p>	<p>undertaken in support of service groups. We consider this approach will assist the distributors understand our classification intent and help stakeholders better understand the basis of the tariffs they are charged by the distributors.</p> <p>We understand the cost of some activities necessary to provide more than one category of services may not be directly attributable. This is a key function of Ergon Energy's approved CAM. That a shared cost is allocated to more than one service category is not reason to adopt a more high level service group description. Nor is it reason to classify services as standard control.</p> <p>We do not, nor could we, propose Ergon Energy not recover its efficient costs incurred in providing distribution services.</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
				because it has not be listed as a 'service' in the classification table.	
AER service group—pre-connection services				<p>Ergon Energy requests that a more generic description and definition be applied, so that there are no perverse outcomes if a particular function or cost is inadvertently omitted from the AER's classification table.</p> <p>Ergon Energy also believes it may be of benefit to incorporate broader NECF definitions and concepts into the service descriptions, so it is clear how pre-connection services will be applied to different classes of customers (such as micro-embedded generators, real estate developers and residential and business customers).</p>	<p>We have addressed Ergon Energy's proposal on high level classifications in attachment 1.</p> <p>We have separately classified real estate development connections.</p>
General connection enquiry services	<p>Provision of standard information and general advice during connection enquiry. Includes:</p> <p>provision of general connection information (e.g. supply availability)</p> <p>advice on process, such as how to complete a connection application</p> <p>and services associated with assessing an initial assessment of a connection applicant's enquiry and provision of a response.</p>	Standard control	Standard control	<p>Ergon Energy notes that it may be beneficial to customers to clarify what is considered to be 'standard information' and 'general advice'.</p> <p>In our view, standard information and general advice should be limited to the provision of high level process related information and the provision of proprietary network information that already exists, or should reasonably be expected to exist.</p> <p>For example, providing guidance to a customer around how to successfully complete a connection application to the DNSP's requirements should fall under this service. Similarly, providing 'off-the-shelf' network data and information which is readily available in the DNSP's corporate systems should also fall under this service.</p>	<p>We have amended our service group definition to improve clarity on the services we consider are general in nature.</p> <p>We confirm Ergon Energy's interpretation of our proposed classification, as described by its comment, is correct. We consider that where site specific analysis is required, this service group would not be applicable.</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
				<p>However, Ergon Energy envisages that this service should not be applied in circumstances where site-specific analysis or engineering input is required in order to respond to a connection applicant's enquiry. If the information does not already exist or needs to be derived, then it is Ergon Energy's expectation that this would fall under either 'Connection Application Services' or 'Pre-connection Consultation Services'. That is, the point at which the DNSP has to undertake customised advice or investigation, the enquiry should become 'site-specific' and trigger the Alternative Control Service arrangements.</p> <p>Ergon Energy requests the AER to confirm this is consistent with the intent of the proposed classifications.</p>	
Connection application services	<p>Services associated with assessing a connection application, making a connection offer and negotiating offer acceptance. Unless otherwise specified, services or activities undertaken under this service group relate to both small and large customer connections. Includes:</p> <p>Application services to assess connection application and making of compliant connection offer.</p> <p>Undertaking design for small customer connection offer (excludes detailed design undertaken after a connection offer has been accepted)</p> <p>Carrying out planning studies and</p>	Alternative control	Alternative Control	<p>Ergon Energy seeks clarification from the AER that this grouping of activities will not restrict a DNSP's pricing arrangements. That is, while some of the costs associated with these activities may be incorporated into a connection application fee, DNSPs will still have the flexibility to develop separate services and prices for these activities, if it chooses to do so.</p> <p>Ergon Energy also wishes to clarify that it is not the AER's intent to limit the application of these services (and associated classifications) to circumstances where a connection application has actually been received. For example, should a protection and power quality assessment or planning study be required (or requested) prior to the lodgement of a connection application, Ergon Energy should have the ability to charge</p>	<p>We confirm Ergon Energy may separately charge for services/activities consistent with the service group description.</p> <p>We consider our service group description makes clear that some activities within the group are applicable although the distributor has not received a connection application.</p> <p>We have removed text specifying the type of connection to which a connection application relates. We have removed reference to dual function assets.</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
	<p>analysis relating to distribution (including sub-transmission and dual function assets) connection applications.</p> <p>Feasibility and concept scoping, including planning and design, for large customer connections.</p> <p>Negotiation services involved in negotiating a connection agreement.</p> <p>Tender process – DNSP may carry out tender process on behalf of connection applicant or DNSP may assist connection application.</p> <p>Protection and Power Quality assessment prior to connection</p>			<p>for this as a type of 'Connection Application Service' or, alternatively, as a 'Pre-connection Consultation Service' under the Alternative Control Service arrangements.</p> <p>Finally, as Ergon Energy and Energex do not have dual function assets, Ergon Energy suggests removing the reference to dual function assets from the third point.</p>	
Pre-connection consultation services	<p>Additional support services provided by the DNSP (on request) during connection enquiry and connection application other than General Connection Enquiry Services and Connection Application Services. Generally relates to services which require a customised or site-specific response and/or are available contestably. Includes:</p> <p>site inspection in order to determine nature of connection (small or large customer connection)</p> <p>provision of site-specific connection information and advice for small or large customer connection</p>	Alternative control	Alternative control	<p>Ergon Energy requests amendments be made to the service description to allow DNSPs the flexibility to offer 'above standard' pre-connection consultation services to small customers on a fee for service basis.</p> <p>For example, while Ergon Energy may usually factor in any costs associated with preliminary designs and plans for small customer connections as part of connection application fees, there may be circumstances where a small customer may request additional or more detailed specification and design options. In these circumstances, we believe an Alternative Control Service classification is appropriate to apply.</p> <p>As noted in the 'Network Services' section,</p>	<p>We have amended the service group description to incorporate small customers.</p> <p>We have responded to Ergon Energy's comment on shared network design for large customer connections against its comments on large customer connections.</p> <p>We have added to the third dot point 'including project scopes and estimates'.</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
	<p>preparation of preliminary designs and planning reports for small or large customer connection, including project scopes and estimates</p> <p>customer build, own and operate consultation services.</p>			<p>Ergon Energy is also seeking confirmation of the AER's expectations around who should fund any design work on the shared network in feasibility and concept scoping phases for large customer connections. In our view, these services should be classified as an Alternative Control Service, and form part of the charges applied to large customers under the 'Pre-connection services' grouping.</p> <p>Finally, we request the AER amend the third dot point to make it clearer that 'preparation of preliminary designs and planning reports for large customer connection' includes project scopes and estimates.</p>	
<p>AER service group—connection services</p>				<p>Ergon Energy requests that a more generic description and definition be applied, so that there are no perverse outcomes if a particular function or cost is inadvertently omitted from the AER's classification table.</p> <p>Ergon Energy also believes it may be of benefit to incorporate broader NECF definitions and concepts into the service descriptions, so it is clear how connection services will be applied to different classes of customers (such as micro-embedded generators, real estate developers and residential and business customers).</p> <p>To assist customers and stakeholders, the AER should note that connection services do not include shared network augmentation to facilitate a connection as these services are included in the description of 'Network Services' above (designing the network and constructing the</p>	<p>We have addressed Ergon Energy's proposal on high level classifications in attachment 1.</p> <p>We have added footnotes to the service groups 'small customer connections' and 'large customer connections' to clarify that these do not include shared network augmentation.</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
Small customer connections ⁴²⁴	<p>Design, construction, commissioning and energisation of connection assets for small customers.⁴²⁵</p> <p>(Generally, small customers are those customers who connect under the Standard Asset Connection tariff class in the DNSP's pricing proposal.)⁴²⁶</p>	Standard control	Standard control	<p>network).</p> <p>At this time, Ergon Energy supports the current Standard Control Service classification for small customer connections and does not believe these connections should be subject to Alternative Control Service arrangements. Please refer to our comments above regarding the classification of small customer connections.</p> <p>We note that there are no regulatory impediments preventing Standard Asset Customers (SACs) (other than subdivisions) from arranging the design and construct of connection assets and gifting these assets to Ergon Energy. However, there are operational issues and business processes to take into consideration.</p> <p>With respect to connection services provided to real estate developers, in Ergon Energy's view these services should be separately distinguished and classified from small customer connections and large customer connections in light of current jurisdictional arrangements and our current Capital Contributions Policy which require developers to fully fund the costs of making a connection between our network and the development. Please refer to our detailed comments in the 'Real estate developers' section above.</p>	<p>We have addressed small customer connections in attachment 1. In summary, we propose to retain the current standard control classification at this time.</p> <p>We intend the current arrangements whereby real estate developers pay the full cost of their connection would continue. We agree with Ergon Energy that clarity would be improved by separately classifying connection services provided to real estate developers. We have added a new service group, below, and propose to classify this group as a direct control and alternative control service. We discuss this issue in attachment 1.</p> <p>We consider that the connection of embedded generators greater than 30 kVA but smaller than 1 MW should be treated as a large customer connection. We have amended the service group description for large customer connections to make this clear. We further consider that embedded generators between 30 kVA and 1 MW should be subject to the same</p>

⁴²⁴ Ergon Energy uses 'minor customer' in place of 'small customer'.

⁴²⁵ Does not include augmentation of the existing network.

⁴²⁶ See the Energex and Ergon Energy tariff schedules, available at their websites: www.energex.com.au and www.ergon.com.au

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
				Ergon Energy also seeks clarification from the AER on how embedded generation connections, in particular embedded generators greater than 30kVA but less than 1MW (i.e. not a micro-embedded generator and smaller than an EG as defined for pricing purposes), will be treated. For clarity, we believe embedded generation connections should be included in the descriptions, and NECF concepts and definitions should be incorporated in the table, where appropriate.	arrangements as embedded generators larger than 1 MW for the purposes of removing a network constraint. Therefore, we have also amended the service group definition for removal of network constraints.
Large customer connections ⁴²⁷	<p>Design and construction of connection assets for large customers.⁴²⁸</p> <p>Generally, large customers are those customers who connect under the Individually Calculated Customer (ICC), Connection Asset Customer (CAC) and Embedded Generator (EG) tariff classes as per the distributor's pricing proposal.⁴²⁹</p> <p>We consider that connection of embedded generators larger than 30 kVA but smaller than 1 MW should be treated as large customer connections.</p>	Alternative control	Alternative control	<p>Ergon Energy believes that a large customer could be defined as a customer who is connecting or modifying a connection at a HV connection, and any customer that is connecting or modifying a connection under an ICC, CAC or EG tariff class. In effect, this would broaden the scope of the Alternative Control Service arrangements to include HV SACs. These customers should be subject to an Alternative Control Service classification for design and construction, but the operation and maintenance of the connection (post-energisation) would still be a Standard Control Service.</p> <p>Ergon Energy notes that changes may be made to tariff classes within the next period as part of the Network Tariff Strategy which could influence the specific customers that may be defined as an ICC, CAC or EG. Ergon Energy will keep the</p>	We do not agree with Ergon Energy's proposal to treat customers connecting to high voltage (HV) assets as large customers. We understand Ergon Energy is concerned that it may be unable to appropriately recover from a small customer the additional costs involved in connecting them to HV assets instead of lower voltage distribution assets. However, we also note that under our current classification approach should the cost of a small customer connection exceed the standard connection cost, the customer is required to make a capital contribution. We consider the capital contribution arrangements should allow Ergon Energy to recover costs appropriately from a customer

⁴²⁷ Ergon Energy uses 'major customer' in place of 'large customer'.

⁴²⁸ **Does not include augmentation of the existing network.**

⁴²⁹ See the Energex and Ergon Energy tariff schedules, available at their websites: www.energex.com.au and www.ergon.com.au

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
				<p>AER abreast of such changes to ensure the general intent of the type of customers intended to be subject to Alternative Control Service arrangements remain.</p> <p>We also have a number of concerns regarding the demarcation between Standard Control and Alternative Control Service associated with large customer connections, which we will cover in our Classification Proposal. For example, who should fund design and construction works related to the shared network where these costs can be directly attributable to a large customer connection application (refer to comments in the 'Network Services' section).</p>	<p>connecting to HV assets. To the extent that the standard costs of a small customer connecting to HV assets are recovered from all customers through standard network charges, this is consistent with the arrangements for small customers connecting to lower voltage distribution assets.</p> <p>We agree that the operation and maintenance of connection assets should remain a standard control service.</p> <p>We have addressed against the service group 'network services' Ergon Energy's proposal that the distributors should be able to charge a large customer for the cost of upstream shared network augmentation works caused by the new large connection. The distributors may set out in their connections policies the circumstances under which a large customer would be charged for shared network augmentation.</p>
Commissioning and energisation of large customer connections	<p>Connection, Commissioning and energisation of Large Customer Connection assets to allow conveyance of electricity. Inspection and testing of connection assets.</p> <p>Includes administration services involved in reconciling the financials of a connection project, processing and finalising network information and contracts in relation to a</p>	Alternative control	Standard control	<p>Ergon Energy notes that it is only the DNSP that can undertake commissioning and energisation of large customer connections. We support the proposed change in classification, and agree the costs associated with commissioning and energising a large customer connection can be (and should be) directly attributed to the large customer benefiting from the service.</p> <p>Ergon Energy also requests that the description be amended to make it clear that costs</p>	We have amended the service group description to clarify that it includes temporary generation.

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
	<p>connection.</p> <p>Includes generation required to supply existing customers while equipment is de-energised to allow testing and commissioning of large customer connection assets.</p>			<p>associated with any generation required to supply existing customers while equipment is de-energised to allow the testing and commissioning of specific large customers connection assets are incorporated into this service.</p>	
<p>Real estate development connection</p>	<p>Design, construction, commissioning and energisation of connection assets for real estate developments.</p>	<p>Alternative control</p>	<p>Standard control</p>		<p>We have separately classified connection services for real estate developers as alternative control. This will allow the distributors to charge developers the full cost of connecting a real estate development to the network. While our classification approach is a change from the current standard control classification, the effect is a continuation of the current arrangements. Our approach to separately classify real estate connections was proposed by both Ergon Energy and Energex. See Ergon Energy's comments above, next to small customer connections. We discuss this issue in attachment 1.</p>
<p>Removal of network constraint for embedded generator</p>	<p>Augmenting the network to remove a constraint faced by an embedded generator.</p> <p>We consider that generators larger than 30 kVA but smaller than 1 MW should be treated as embedded generators for the purpose of removing network constraints.</p>	<p>Alternative control</p>	<p>Standard control</p>	<p>Ergon Energy considers that the description could be improved to clarify that it includes any necessary upstream works associated with the connection. That is, it should not just be the net benefit concept outlined in the AER's Connection Charge Guidelines.</p> <p>Ergon Energy also believes that measures will need to be put in place to ensure that embedded generators do not fund upstream shared network works that are already committed or incurred as part of the DNSPs network plans (i.e. already</p>	<p>We agree that the distributors should be able to charge embedded generators for upstream works associated with removing a network constraint. Consistent with our approach to shared network augmentation caused by large customer connections, we are currently unable to see how such an alternative control service would work in practice. We invite the distributors to set out in their connection policies the</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
				<p>planned to be funded under Standard Control Network Services). Ergon Energy considers, DNSPs would need to develop high level principles on when costs would be payable. These principles could be approved by the AER as part of the connection policy (if NECF applies).</p> <p>As highlighted above, the AER could also consider an Alternative Control Service classification for augmenting and extending the shared network, where this is directly attributable to facilitating a large customer connection in line with the AER's proposed approach to Embedded Generators (EGs)</p> <p>Finally, the AER should also ensure that the description clearly indicates that this service applies to EGs only (as defined for pricing purposes by the DNSP). That is, it should not capture any embedded generators that we would otherwise classify as a SAC. These customers will still receive a 'user pays' signal as they will be subject to the cost-revenue-test under the capital contributions policy (or connection policy, if NECF is introduced).</p>	<p>circumstances in which an embedded generator would be expected to fund the cost of such works. The distributors will submit connections policies with their regulatory proposals. In our draft determination we may consider the circumstances to have changed and may change our classification approach to allow the distributors to charge for upstream works.</p>
Temporary connections	Customer requests a temporary connection for short term supply (e.g. temporary builders supply, blood bank vans, school fetes etc.).	Alternative control	Alternative control	<p>Ergon Energy seeks clarification that temporary connection services are only intended to capture connections that are to be commissioned for a very short period of time (i.e. as indicated by the examples provided in the description).</p> <p>Ergon Energy does not support this service being applied to connections that have a short</p>	<p>We agree clarity can be improved by specifying that temporary connections are for short term supply only. To address Ergon Energy's comment, we have added 'short term supply' to the service group description for temporary connections. We consider amending the service group descriptions for small and</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
				<p>term asset life. That is, connections that have a permanent location but the customer's requirements are less than the usual asset life (e.g. a mine with a 10 year life). Ergon Energy does not believe that these types of connections should be treated any differently to other types of 'permanent' connections, albeit that the connection may be temporary in nature.</p> <p>Therefore, Ergon Energy suggests that 'short-term supplies' for temporary connections in permanent locations (other than those for temporary builders' supplies) be incorporated within the descriptions for small customer and large customer connections.</p>	large customer connections is less straightforward.

AER service group—post connection services

Operate and maintain connection assets	Works to operate, maintain, repair and replace connection assets owned by or gifted to the DNSP to a technically acceptable standard. Excludes works initiated by a customer, which is not required for the efficient management of the network or for DNSP purposes (such as customer requests to provide or maintain connection assets to a higher standard).	Standard control	Standard control	Nil comment.	
Connection management services	Work initiated by a customer which is specific to a connection point. Includes:	Alternative control	Alternative control	Ergon Energy considers the description for 'Connection management services' could be improved through the use of some more high level definitions and descriptions of services.	<p>We have addressed Ergon Energy's proposal on high level classifications in attachment 1.</p> <p>We have moved 'coverage of low</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
	<p>Supply abolishment.</p> <p>Move point of attachment.</p> <p>Re-arrange network connection assets – network assets are re-arranged at customer's request.</p> <ul style="list-style-type: none"> ▪ Overhead service line replacement – customer requests the existing overhead service to be replaced .e.g. as a result of a point of attachment relocation. No material change to load. ▪ Auditing services – auditing of connection assets after energisation to network. ▪ Protection and power quality assessment. e.g. embedded generation connected to network. ▪ Customer requested works to allow customer or contractor to work close. ▪ coverage of low voltage mains (tiger tails) – customer requests the line close to a construction site to be physically covered in order to provide safety to parties work in close proximity ▪ Temporary disconnections and 			<p>Additionally, Ergon Energy requests that the AER move services which are not necessarily specific to a connection point to the 'Ancillary Network Services' grouping. For example, the re-arrangement of network assets is not usually specific to a connection point. Rather, it is requested by a specific customer or appropriate third party (e.g. Department of Main Roads). Tiger tails can also be placed on shared network assets, and not just those assets specific to a connection point.</p> <p>Finally, Ergon Energy suggests removing the following from the description:</p> <p>"A reserve feeder is negotiated with customers specifically requesting continuity of supply should the feeder providing normal supply to their connection experiencing interruption."</p> <p>This is because Ergon Energy considers this as a type of connection service above minimum requirements (which is already separately listed).</p>	<p>voltage mains (tiger tails)' to the ancillary network services group.</p> <p>A service for the re-arrangement of network assets that are not connection related is provided separately under 'other recoverable works'. For clarity, we have added 'connection' to the description of 're-arrange network assets' provided here.</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
	<p>reconnection (including de-energisations and re-energisations) that may involve a line drop. e.g. community events.</p> <ul style="list-style-type: none"> ▪ Supply enhancement. e.g. upgrade from single phase to three phase. ▪ Provision of connection services above minimum requirements. ▪ Upgrade from overhead to underground service. ▪ A reserve feeder is negotiated with customers specifically requesting continuity of supply should the feeder providing normal supply to their connection experiencing interruption. ▪ Customer consultation or appointment (if requested on B2B service order). ▪ Rectification of illegal connections or damage to overhead or underground service cables. ▪ Customer request for ad-hoc reconnections/disconnections 				

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
	<p>for regular but short periods of time, for example holiday homes.</p> <p>De-energisation:</p> <ul style="list-style-type: none"> ▪ Retailer requests de-energisation of the customer's premises (business or after hours) where the de-energisation can be performed (e.g. pole, pillar or meter isolation link). ▪ Retailer requests de-energisation of the customer's premises – Main switch seal (business or after hours). <p>Re-energisation:</p> <ul style="list-style-type: none"> ▪ Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account (business or after hours). ▪ Retailer requests a re-energisation of the customer's premises following a main switch seal (business or after hours). ▪ Reading provided for an active 				

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
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site.

- Retailer requests a re-energisation of the customer's premises after a physical disconnection and premises requires a visual examination.

Accreditation of alternative service providers and approval of their designs, works and materials	<p>Accreditation of service providers that meet competency criteria.</p> <p>Approval of third party design, works and materials:</p> <ul style="list-style-type: none"> ▪ Review, Inspection and Auditing of design and works carried out by an alternative service provider prior to energisation. ▪ Certification of non-approved materials – approval of non-approved materials to be used on the network. 	Alternative control	Standard control/ Alternative control	Nil comment.	
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AER service group—metering services

Type 5 and 6 metering installation	Includes on site connection of a new meter at a customer's premises, and on site connection of an upgraded meter at a customer's premises where the customer initiates the upgrade. Excludes installation of replacement types 5 and 6 meters initiated by the distributor.	Alternative control	Standard control	Ergon Energy considers that the initial installation of a meter should not be included in this service group. Rather, it should be included within the 'Type 5 and 6 metering provision, maintenance, reading and data services' group. This is because, for new connections, these costs are typically capitalised as part of the connection project. Therefore, for expenditure	We agree that type 5 and 6 metering installation may be added to type 5 and 6 metering provision, maintenance, reading and data services. We have merged the two service groups in our classifications table. We discuss this issue in attachment 1.
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Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
				<p>forecast purposes, it would be simpler to include these costs as part of the same grouping which contains the capital costs associated with the meter assets themselves.</p> <p>Additionally, if the only remaining service in this group relates to customer initiated meter upgrades, then Ergon Energy considers this could be incorporated within the 'Auxiliary Metering Services' group.</p> <p>Ergon Energy also notes the AER's comment that Energex does not provide Type 5 meters. In actuality, neither Ergon Energy nor Energex provide Type 5 metering as there are currently jurisdictional restrictions in place in Queensland for Type 5 metering. However, Ergon Energy would prefer that the reference to Type 5 remain in the classification table, to allow the Alternative Control Service classification to continue in the event that these regulatory barriers are removed.</p>	<p>We note Ergon Energy's support for our approach to classify both type 5 and 6 metering services.</p>
<p>Type 5 and 6 metering provision, maintenance, reading and data services</p>	<p>Meter provision refers to meter selection, procurement, programming, testing and management of NMI standing data according to the rules.</p> <p>Meter maintenance covers scheduled maintenance, meter inspection, load control relay maintenance, removal of meter and meter tampering.</p> <p>Meter reading refers to quarterly or other regular reading of a meter.</p> <p>Metering data services include collection, processing, storage and delivery of metering data, remote or self-reading at difficult to access sites, provision of metering</p>	<p>Alternative control</p>	<p>Standard control</p>	<p>Ergon Energy notes that Table 4 of the AER's Preliminary Positions Paper makes reference to the capital cost associated with purchasing metering equipment. However, it is unclear from the description set out in Appendix B whether the capital cost of meters is intended to be included in this service group. Ergon Energy requests clarification from the AER in this regard.</p> <p>As noted above, Ergon Energy believes the initial installation of a meter should also be incorporated into this service group.</p> <p>Ergon Energy also requests guidance from the</p>	<p>To clarify, our service group description refers to meter 'procurement'. We consider, and intend, that this includes the capital cost of the meter.</p> <p>We consider metering services are distinct from network services. While we understand metering (and pricing) services can be seen as supporting the broader network by helping to smooth peak demand, by unbundling metering from network services we are making a clear distinction between the two. Our reasons for unbundling metering are set</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
	<p>data from previous 2 years, ongoing provision of metering data.</p> <p>Meter Data Services provided as part of general obligations as a local network service provider in accordance with the rules.</p>			<p>AER on how we would treat capex for meters that are installed to address demand management initiatives and network augmentation constraints (i.e. for DNSP purposes which are for the benefit of all customers connected to the shared network). Similarly, how capex should be treated for non-compliant metering asset replacement programs, Ergon Energy expects these costs will need to be incorporated into any metering asset base.</p> <p>As previously highlighted, Ergon Energy also incurs a range of costs associated with services provided as part of our general obligations as a Local Network Service Provider. These costs are incurred even if Ergon Energy is not the MP or RP under the NER. For example, Ergon Energy still needs to warehouse and maintain metering data for all installations, including where we are not the MP or RP.</p> <p>Further, some systems currently used by Ergon Energy are not exclusively dedicated to Type 5 and 6 data services. That is we use the same systems to collect and process metering data for network billing purposes (and for all meter types), as well as for providing meter data services in accordance with our obligations under the NER. This means there may be practical difficulties in isolating and quantifying separate costs associated with the administration and management of Type 5 and 6 metering installations for expenditure forecast purposes. Ergon Energy is currently examining this issue.</p> <p>Ergon Energy does not believe it is appropriate</p>	<p>out in attachment 1.</p> <p>In response to Ergon Energy's query about capex for non-compliant metering asset replacement, in so far as it relates to type 5 or 6 metering, we consider this service is addressed by 'meter maintenance'. This covers 'meter tampering'. As a component of 'Type 5 and 6 metering provision, maintenance, reading and data services', we propose to classify this service as alternative control. Should inspection and rectification of meter tampering relate to non-type 5 or 6 metering, we have added a service to 'ancillary metering services'.</p> <p>Consistent with our approach to classify load control as a network service, we have removed 'load control relay maintenance' from this service group.</p> <p>We consider the issues described by Ergon Energy around the allocation of shared costs to service groups are commonly experienced by network service providers. We consider this is a cost allocation issue. The costs of systems operated by a distributor in support of more than one service group should be allocated to service groups consistent with the distributor's approved CAM.</p> <p>Throughout this F&A we refer to the</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
				<p>to recover such 'shared' costs from a specific sub-set of customers that pay Alternative Control Service metering charges. Therefore, the AER's classification must ensure such services are classified as a Standard Control Service within the 'Network Services' grouping.</p> <p>Finally, Ergon Energy suggests spelling out National Electricity Rules in the last point.</p>	<p>National Electricity Rules as 'the rules' or NER. We consider it is reasonable to retain this approach in the table of service classifications.</p>
Type 7 metering services	Administration and management of type 7 metering installations in accordance with the rules and jurisdictional requirements. Includes the processing and delivery of calculated metering data for unmetered loads, and the population and maintenance of load tables, inventory tables and on/off tables.	Standard control	Standard control	<p>It should be noted that a number of Ergon Energy's metering systems and resources support dual functions and purposes. Therefore, there may be practical difficulties in isolating and quantifying separate costs associated with the administration and management of Type 7 metering services from other types of metering installations. Ergon Energy is currently examining this issue.</p> <p>Ergon Energy also suggests spelling out National Electricity Rules.</p>	<p>We consider this is a cost allocation issue. As we note above, the costs of systems operated by a distributor in support of more than one service group should be allocated to service groups consistent with the distributor's approved CAM.</p>
Auxiliary metering services	<p>Off-cycle meter read, including:</p> <ul style="list-style-type: none"> ▪ special meter reads ▪ move in move out meter reads ▪ check read – check the accuracy of the meter reading. <p>Testing for type 5 and 6 metering installations - customer requested meter accuracy testing.</p> <p>Meter inspection and investigation – a request to conduct</p>	Alternative control	Alternative control/ Standard control	<p>In general, auxiliary metering services should be services undertaken at the request of a customer or retailer. Ergon Energy believes that in circumstances where services within this grouping are undertaken to satisfy DNSP purposes or obligations, then these services should not be subject to a non-building block arrangement. Rather, they should form part of either our 'Network Services' (i.e. Standard Control Service) or part of the 'Type 5 and 6 metering provision, maintenance, reading and data services' grouping (i.e. Alternative Control Service). Ergon Energy requests the AER clarify that this is the intent of the proposed</p>	<p>We consider this service group relates to services requested by customers or another third party, or are otherwise ad hoc in nature and related costs can be attributable to an identifiable customer.</p> <p>We have added 'metering installations' to the relevant part of the service group description.</p> <p>Ergon Energy's proposal to create a service 'type 5 to 7 non-standard metering services' would create a very</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
	<p>a site review of the state of the customer's metering installation without physically testing the metering equipment.</p> <p>Alterations and additions to current metering equipment, includes:</p> <ul style="list-style-type: none"> ▪ meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment ▪ exchange meter – customer requests exchange of their current meter (e.g. for alternative metering configuration/consolidation of multiple meters for one meter), or customer requests exchange of their current meter for a solar photovoltaic meter. <p>Provision of low voltage (LV) current transformers (CT).</p> <p>Type 5 to 7 non-standard metering data services.</p> <p>Replacement or removal of a type 5 or 6 meter instigated by a customer switching to a non-type 5 or 6 meter that is not covered by any other fee.</p> <p>Meter re-seal – where the customer has caused the meter to need re-sealing (e.g. by having electrical work done on site).</p> <p>Install additional metering.</p> <p>Reconfigure meter.</p> <p>Meter Exit Fee – recovery of stranded asset costs associated with the removal of meter/s from customer's</p>			<p>classifications.</p> <p>Ergon Energy also suggests changing the description of “Testing for type 5 and 6 meters...” to “Testing for type 5 and 6 metering installations”. This will provide us the ability to recover costs of meter testing, as well as the costs of LV CTs that also form part of the customer's metering installation. This would only be applicable to regulated customers.</p> <p>Additionally, “Type 5 to 7 non-standard metering data services” should be changed to “Type 5 to 7 non-standard metering services”. This will allow for a broader cost recovery of additional metering services above minimum requirements (e.g. providing energy pulsing output for a customer, interface to building management system, and non-standard data services).</p> <p>We also seek clarification on the scope of the proposed meter inspection and investigation charge under the ‘Auxiliary Metering Services’ grouping and the metering inspection under the ‘Type 5 and 6 metering provision, maintenance, reading and data service’ grouping. Ergon Energy expects that:</p> <ul style="list-style-type: none"> ▪ Any meter inspection and investigation initiated by the customer would incur the auxiliary metering service fee ▪ Any meter inspection forming part of the approved Meter Asset Management Plan activities would be covered by the Type 5 and 6 metering provision, maintenance, 	<p>broad category of services characterised as non-standard. We consider it unnecessary to create such a broad category in the context of a number of non-standard metering services already defined by our proposed classifications. Were we to adopt Ergon Energy's proposed approach, we consider it would create uncertainty about how such non-standard services should be treated. We prefer that Ergon Energy propose additional non-standard metering services we may separately consider and classify appropriately.</p> <p>We intend that customer requested meter inspection and investigation would incur an alternative control service charge under this service group. We agree with Ergon Energy that standard meter inspections and maintenance activity remains part of the type 5 and 6 metering services.</p> <p>We agree with Ergon Energy that load control services related to the network should remain part of the network services and classified standard control. We have added ‘metering related’ to the description of load control installation in this service group description to differentiate load control for metering purposes.</p> <p>We agree with Ergon Energy's proposal</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
	<p>premises before the end of their useful life at the request of the customer (or customer's retailer) due to a change in Responsible Person /Meter Coordinator.</p> <p>Install metering related load control.</p> <p>Remove local control relay or time clock.</p> <p>Change load control relay channel at retailer, customer or other third party request, that is not a part of initial load control installation, nor part of standard asset maintenance or replacement.</p>			<p>reading and data services charge.</p> <p>Ergon Energy also notes that costs associated with load control should only apply to Alternative Control Services to the extent they relate to the actual meter. The provision of the load control equipment that is separate to the meter, and necessary for safe, secure and reliable operation of the network should be a 'Network Service', and therefore a Standard Control Service.</p> <p>Ergon Energy would also like to add an additional load control related service 'Change load control relay channel at retailer or customer request' (refer comments in the 'Proposed additional services' section above).</p>	<p>to establish an additional service in this group for changing load control relay at customer or retailer request. We are conscious that parties other than the customer or a retailer may also request such a service—for example, demand aggregators. For this reason, we propose to specify that this service relates to a request from a customer or other third party, as opposed to only a retailer.</p>
AER service group—ancillary network services				<p>As highlighted previously, Ergon Energy believes DNSPs are in the best position to design and future proof the list of distribution services, as it applies to their network and service offerings. Ergon Energy is happy to work with the AER to make further refinements to the classification table. We will revise the table over the coming weeks and provide it to the AER.</p>	<p>We note Ergon Energy's comment.</p>
<p>Services provided in relation to a Retailer of Last Resort (ROLR) event</p>	<p>Distributors may be required to perform a number of services as a distributor when a ROLR event occurs. These include:</p> <p>Preparing lists of affected sites, and reconciling data with Australian Energy Market Operator listings; handling in-flight transfers; identifying open service orders raised by the failed retailer and determining actions to be taken in relation to those service orders; arranging estimate reads for the date of the ROLR event and providing data for final</p>	<p>Alternative control</p>	<p>Not currently classified</p>	<p>Ergon Energy believes a detailed list of services creates limitations around what should be included in this service. We prefer a broader definition.</p> <p>Also, if the current list is maintained, Ergon Energy suggests spelling out the reference to AEMO (i.e. Australian Energy Market Operator).</p>	<p>We do not agree with Ergon Energy's proposed approach. We are required to classify distribution services. A 'broader definition' may give rise to uncertainty about our intended classification decisions.</p> <p>We have spelt out Australian Energy Market Operator.</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
	network use of system (NUOS) bills in relation to affected customers; preparing final invoices for NUOS and miscellaneous charges for affected customers; preparing final debt statements; extracting customer data, providing it to the ROLR and handling subsequent enquiries; handling adjustments that arise from the use of estimate reads; assisting the retailer with the provision of network tariffs to be applied and the customer move in process; administration of any 'ROLR cost recovery scheme distributor payment determination'.				
Other recoverable works	<p>Customer requests the provision of electricity network data including pole assess information.</p> <p>Specific request for the provision of zone substation data.</p> <p>Bundling of cables carried out at the request of another party.</p> <p>Provision of services, other than standard connection, for approved unmetered equipment, public telephones, traffic lights and public BBQs.</p> <p>Customer requested appointments.</p> <p>Attendance at customer's premises to perform a statutory right where access is prevented.</p> <p>Rearrangement of assets (other than connection assets).</p> <p>Conversion to aerial bundled cables.</p> <p>Aerial markers.</p>	Alternative control	Alternative control	<p>Ergon Energy considers that the service group 'Other recoverable works' is unclear in terms of distinguishing between Alternative Control Services, Standard Control Services and unregulated services. For the benefit of customers, Ergon Energy considers the AER should make their expectations clear around the distinguishing factors which make a service Alternative Control (and subject to direct revenue and price control) as opposed to being unregulated.</p> <p>We appreciate the addition of the 'Customer requests the provision of electricity network data including pole assess information' and 'Specific request for the provision of zone substation data' services. However, we are unclear whether this is broad enough to cover our concerns raised in the 'Proposed additional services' section relating network data.</p> <p>Ergon Energy should be able to charge for a wasted truck visit where the retailer/customer cancels a service order and the truck has already left the depot (refer to the 'Proposed</p>	<p>We consider the key attribute delineating these alternative control services from standard control services is that these are services requested by, or otherwise needing to be performed because of, a customer or another party. These services are also not routine in nature. That is, they are not part of the standard process of establishing or maintaining standard electricity supply.</p> <p>These services are clearly not unregulated because we have included them in this service group and classified the group as alternative control.</p> <p>It is our intention that Ergon Energy (or Energex) be able to charge for wasted truck visits, or wasted attendance. However, we consider a wasted attendance is a component of a service, not a service itself.</p> <p>'Rearrangement of assets' is already</p>

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
	<p>Parallel generator applications.</p> <p>Witness testing.</p> <p>Reserve feeder.</p>			<p>additional services' section above).</p> <p>Ergon Energy also requests the following services to be added to this service group:</p> <ul style="list-style-type: none"> Services not specific to a connection point currently listed under 'Post-connection services' (e.g. removal / relocation of assets at customer request) Assessment of Parallel Generation Applications Witness Testing Provision of network data (not covered by other services). 	<p>listed in this service group description.</p> <p>'Parallel generation applications' is already included in this service group.</p> <p>We have added 'witness testing' to this service group. We discuss this issue in attachment 1.</p> <p>Network data requests are already covered by this service group description.</p>

AER service group—public lighting

Provision, construction and maintenance of public lighting.	<p>Application assessment, design, review and audit public lighting services.</p> <p>Provision, construction and maintenance of new street lighting services.</p> <p>Alteration, repair, relocation, rearrangement or removal of existing street light assets.</p> <p>Provision of glare shields, vandal guards, luminaire replacement with aero screens.</p> <p>A fee for the residual asset value of non-contributed public lights when removed from service before the end of their</p>	Alternative control	Alternative control	<p>Ergon Energy currently treats requests to remove / relocate street lights as a Quoted Service. That is, they are not treated differently to requests to remove / relocate other distribution assets. Ergon Energy does not support grouping this service with other street lighting services that are included in the street lighting building block and believes that a new service should be established.</p>	<p>Do not agree. Relocation of street lighting assets is clearly a street lighting related service. Ergon Energy has not provided a rationale for this to be classified alternative control as a separate service group. The pricing of a specific service as either fee based or quoted is not a classification issue.</p>
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Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
	useful life at the request of the customer. Operating street lighting assets including handling enquiries and complaints and dispatching crews to repair assets.				
	New public lighting technologies, including trials.				
Emerging or new public lighting technology.	Energy efficient retrofit (including where customer requests to retrofit existing assets before end of life).	Alternative control	not classified	Ergon Energy appreciates the AER's inclusion of this new service in the table.	
Unclassified distribution services				Ergon Energy notes that a number of these services are specific to Energex. Ergon Energy is happy to work with the AER to make further refinements to the classification table.	We note Ergon Energy will work with us to refine our service group descriptions and classification decisions.
Type 1 to 4 metering	Contestable metering services.	Unclassified	Unclassified	Nil comment.	
Emergency recoverable works	Work to repair damage to the distribution network caused by an identifiable third party from whom costs may be recovered.	Unclassified	Alternative control	Ergon Energy notes that the description refers to "identifiable third party". The AER has not provided indication of how costs will be recovered if the responsible party is unknown. Due to difficulties in recovering costs, we also believe costs to repair damage caused by an identifiable party should remain a direct control service. Please refer to our comments above.	Do not agree. We discuss this issue in attachment 1.

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
Watchman	Unmetered light mounted on customer's property or distribution pole for security purposes. Charge for fixed capital cost of installing light.	Unclassified	Unclassified	Nil comment.	
Shared assets	Pole/duct rentals for non-electricity related purposes (e.g. telecommunications) and relocation of third party cables.	Unclassified	Unclassified	Ergon Energy seeks clarification from the AER that this grouping includes services related to the National Broadband Network. Ergon Energy also has a wholesale telecommunications arm and wholly-owned subsidiary, Nexium Telecommunications, which provides telecommunication services to third parties. This service should be classified as a non-distribution service that is unregulated in the section below.	We consider shared asset issues are dealt with by our Shared Asset Guideline. Further, that shared assets themselves are not services. We also agree with Ergon Energy that unclassified services provided with shared assets are generally not distribution services. On balance, we give weight to the view that shared assets are not themselves services. As such, we have removed this service from our classifications table.
Distribution services provided in unregulated isolated networks		Unregulated	Unregulated	Ergon Energy considers that this service should be added as an unregulated service. It relates to Ergon Energy's ownership and operation of 33 isolated system networks (other than the Mount Isa-Cloncurry supply network which is subject to economic regulation by the AER.	Agreed. We have added this service.
Non-distribution services that are unregulated					
Rental and Hire Services	Rental of Energex distributor owned property.	Unregulated	Unregulated	Ergon Energy believes that the reference to 'Energex' should be removed and replaced with 'distributor-owned'.	Agreed. We have amended the service group description.
Test, inspect	Calibration and testing of equipment for external party	Unregulated	Unregulated	Nil comment.	

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
and calibrate	products.				
Property Searches	Customers request the distributors undertake conveyancing property searches, conduct easement negotiations or purchase negotiations.	Unregulated	Unregulated	Ergon Energy believes this service should be expanded to include circumstances where customers approach Ergon Energy to conduct easement negotiations and /or purchase (where they are responsible for the works). As such, the service group should be renamed 'Property Services'.	Agreed. We have amended the service group.
Contracting Services to other network service providers NSPs	Services, such as specialist cable jointers, provided to other network service providers.	Unregulated	Unregulated	Ergon Energy believes that the reference to 'Ergon' should be removed and 'NSPs' should be spelt out in full (i.e. network service providers).	Agreed. We have amended the service group description.
Provision of training to external parties	Specialist post and pre-trade training provided to external parties.	Unregulated	Unregulated	EsiTrain is specific to Energex and should not be referenced in this table. We suggest replacing this term with 'distributors'.	Agreed. We have amended the service group title and description.
Equipment Services	<p>Safety testing of equipment such as:</p> <ul style="list-style-type: none"> ▪ insulating gloves ▪ live line hot sticks and rubber products ▪ insulating mats and covers ▪ voltage and phasing detectors, operational sticks ▪ harnesses, climbing kits, rescue kits ▪ step/extension ladders, pole platforms. 	Unregulated	Unregulated	Nil comment.	

Service group	Further description (if any)	AER's proposed classification 2015–20	Current classification 2010–15	Ergon Energy comment	AER response
Sale of inventory, asset or scrap		Unregulated	Unregulated	Ergon Energy wishes to clarify that this service relates to unregulated assets that are not subject to AER regulation.	Agreed.
Operate and Maintain large customer connections	Contract to provide operate and maintain services for connection assets owned by customer	Unregulated	Unregulated	Nil comment.	

Appendix E – Jurisdictional and legacy issues

This appendix sets out a description of issues raised by Ergon Energy but which it now agrees are:

- resolved, on the basis of our *Preliminary positions F&A paper for Qld, or*
- on which it proposes to liaise with us.

On these issues, Ergon Energy did not seek a further statement from us in this F&A.⁴³⁰ The content of this appendix is sourced from our preliminary positions F&A paper for Qld.

Negotiating framework – resolved

In 2008, Ergon Energy submitted that its regulatory proposal need not include a negotiating framework where no negotiated distribution services were proposed.⁴³¹ In the current F&A we agreed that a distributor need not submit a negotiating framework if it does not provide negotiated services.⁴³² We further noted that we may classify services as negotiated services in our final F&A or preliminary determination. This may be the case even if the distributor does not propose any negotiated services in its regulatory proposal. In these circumstances we will notify the distributor of the change of classification and request that it include a negotiating framework as part of its revised regulatory proposal.⁴³³ This remains our position.

Mt Isa–Cloncurry network – resolved

Ergon Energy owns the Mt Isa–Cloncurry isolated distribution network. In 2008, Ergon Energy sought clarification on how we would treat this isolated network.⁴³⁴ At the time, the Queensland Government was preparing to transfer regulatory responsibility for this network from the QCA to us.

Regulatory responsibility for the Mt Isa–Cloncurry network has now transferred to us. Therefore, Ergon Energy may include this isolated network in its regulatory proposal.⁴³⁵ We will assess this element of Ergon Energy's regulatory proposal, as part of our distribution determination process, under the relevant provisions of the rules.

Asset categories, asset lives and asset tax lives – resolved

In 2008, Ergon Energy sought confirmation from us that it may use in its then upcoming regulatory proposal the same asset categories it previously reported to the QCA.⁴³⁶ Ergon Energy also sought confirmation that:

- public lighting assets would not be included in its regulatory asset base if they do not provide standard control services
- asset lives and asset tax lives would be treated in a particular way.⁴³⁷

⁴³⁰ Ergon Energy, *Submission on the framework and approach preliminary positions paper*, 19 February 2014, pp. 18–19.

⁴³¹ Ergon Energy, *Submission to the AER in response to 'preliminary positions – framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, August 2008, p. 20.

⁴³² AER, *Final framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, November 2008, p. 48.

⁴³³ NER, clause 6.8.2(c)(5).

⁴³⁴ Ergon Energy, *Submission to the AER in response to preliminary positions – framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, August 2008, p. 14.

⁴³⁵ Section 10, *Electricity National Scheme (Queensland) Act 1997*.

⁴³⁶ Ergon Energy, *Submission to the AER in response to preliminary positions – framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, August 2008, p. 14

Asset values are a key determinant of a distributor's revenues, as set out in our distribution determinations. In turn, the assumed 'life' of an asset is an aspect of determining its value. Similarly, asset tax lives are an aspect of determining a distributor's tax liability. We think the issues raised by Ergon Energy in 2008 were resolved in the context of our last Ergon Energy determination. To the extent Ergon Energy requires further comment, we discuss these issues again below.

Consistent with our response to these issues set out in the current F&A, we do not consider it would be appropriate for us to commit to an approach to determining asset values outside the distribution determination process.⁴³⁸ We will review Ergon Energy's asset categories and remaining asset lives when making our distribution determination, in consultation with stakeholders. We expect Ergon Energy to submit a completed roll forward model and a post-tax revenue model as required under the rules.⁴³⁹ We expect Ergon Energy to explain any deviations from asset classes and asset lives used for these models in our last determination.

On public lighting, we again confirm that a distributor's RAB should include only assets that provide standard control services. We currently classify Ergon Energy's public lighting services as alternative control services. Our preliminary position, set out in this paper, is to maintain Ergon Energy's public lighting services as alternative control services.

Regulatory asset base value – resolved

In 2008, Ergon Energy asked us to approve its proposed adjustments to its RAB value.⁴⁴⁰ At that time, Ergon Energy proposed a 2005 RAB value slightly lower than had previously been calculated. The proposed adjustment included two elements. First, an increase in RAB value of \$34.2 million (\$July 2005) to reflect actual capex in the final year of the previous regulatory period. Second, a decrease in RAB value of \$39 million (\$July 2005), reflecting our acceptance of capital allowances instead of the QCA's use of inventory value.

Our current F&A sets out our decision to accept part of Ergon Energy's proposed adjustments and to consider the remaining part within our 2010 distribution determination.⁴⁴¹ Ergon Energy has not proposed a similar adjustment for us to address in our next F&A. We will consider Ergon Energy's RAB value as part of our distribution determination.

Prudency review – resolved

In 2008, Ergon Energy submitted that the rules do not provide for us to review the prudency of its capital expenditure during the 2005–10 regulatory control period.⁴⁴² At that time, we were not able to adjust a distributor's future RAB value in response to our assessment of the prudency of past capex. The rules have now changed to allow us to adjust a distributor's RAB in response to the prudency of a distributor's past capex.⁴⁴³ However, this is not relevant to our next distribution determination. Transitional provisions prevent us adjusting a distributor's RAB for the prudency of capex incurred in or before the transitional regulatory period—Ergon Energy's current regulatory control period.⁴⁴⁴ So,

⁴³⁷ Ergon Energy's 2008 submission set out a proposed approach to the treatment of asset lives.

⁴³⁸ AER, *Final framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, November 2008, p. 50.

⁴³⁹ NER, clause 6.8.2.

⁴⁴⁰ Ergon Energy, *Submission to the AER in response to preliminary positions – framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, August 2008, p. 13.

⁴⁴¹ AER, *Final framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, November 2008, p. 53.

⁴⁴² Ergon Energy, *Submission to the AER in response to preliminary positions – framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, August 2008, p. 14.

⁴⁴³ NER, clause S6.2.2A(f).

⁴⁴⁴ NER, clause 11.56.5.

under the rules, we are not able to adjust Ergon Energy's RAB for the prudence of its past capex until its 2015–20 distribution determination.

For the distribution determination to which this preliminary F&A relates, the position stated in the current F&A remains relevant. That is, we will review past capex (and opex) to inform our decision on the forecast capex (and opex) to apply in the next regulatory control period.

Cost pass throughs – resolved

In 2008, Ergon Energy and Energex sought confirmation that they could nominate significant input cost variations as pass through events in their regulatory proposals.⁴⁴⁵ Under the rules, distributors may submit for our approval proposals to increase the revenues they recover from consumers in response to significant cost increases in pre-approved categories.⁴⁴⁶ We determine the acceptable categories of pass through as part of our distribution determinations.

In response to Ergon Energy's 2008 request, the current F&A states we will consider the inclusion of additional pass through events as part of our distribution determination.⁴⁴⁷ It further states that we think it inappropriate to indicate our likely approach outside of the distribution determination process. We maintain this position. We will make our decision on nominated pass through events as part of our distribution determination, after assessing regulatory proposals and stakeholder submissions.

Ergon Energy and Energex also sought, in 2008, confirmation of our approach to assessing the materiality of cost pass through events. The current F&A states that we considered it unnecessary to indicate our likely approach in the F&A.⁴⁴⁸ We note that the revised rules define 'materially' as:⁴⁴⁹

...an event results in a Distribution Network Service Provider incurring materially higher or materially lower costs if the change in costs (as opposed to the revenue impact) that the Distribution Network Service Provider has incurred and is likely to incur in any regulatory year of a regulatory control period, as a result of that event, exceeds 1% of the annual revenue requirement for the Distribution Network Service Provider for that regulatory year.

Ergon Energy and Energex in 2008 further sought confirmation from us that cost pass through events could apply to alternative control services in addition to standard control services.⁴⁵⁰ The current F&A states that this forms part of our distribution determinations.⁴⁵¹ That is, if distributors propose pass throughs related to alternative control services, we will assess such proposals as part of our distribution determination. This remains our position.

Application of security of supply standards – resolved

In 2008, Ergon Energy and Energex sought our confirmation that the relevant security of supply standards for its networks were those approved by the Queensland Government in its:⁴⁵²

⁴⁴⁵ Ergon Energy, *Submission to the AER in response to preliminary positions – framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, August 2008, p. 16.

⁴⁴⁶ NER, clause 6.6.1.

⁴⁴⁷ AER, *Final framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, November 2008, p. 54.

⁴⁴⁸ AER, *Final framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, November 2008, p. 55.

⁴⁴⁹ NER, Glossary.

⁴⁵⁰ Ergon Energy, *Submission to the AER in response to preliminary positions – framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, August 2008, p. 18.

⁴⁵¹ AER, *Final framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, November 2008, p. 56.

⁴⁵² Ergon Energy, *Submission to the AER in response to preliminary positions – framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, August 2008, p. 19.

- Electricity Distribution and Service Delivery review recommendations⁴⁵³
- Associated Queensland Government action plan.

The current F&A states that a distributor's required expenditure should achieve compliance with all applicable regulatory obligations or requirements.⁴⁵⁴ Further, we stated that we would be guided by the Queensland Department of Mines and Energy's position (as it was named at the time) on the security of supply standards applicable to the distributors.

In considering our distribution determination for the next regulatory control period, we will again refer to the Queensland Government's position on security of supply issues. We note that the relevant Queensland Government agency is now the Department of Energy and Water Supply (DEWS). We have begun to liaise with DEWS on the upcoming Queensland distribution determination process. We will continue to liaise on relevant issues.

Treatment of solar feed-in tariffs – Ergon Energy will liaise with us

Ergon Energy asked us to address the treatment of its recovery of costs related to Queensland's solar feed-in tariff.

Ergon Energy and Energex meet the cost incurred by retailers in paying a feed-in tariff to consumers with photovoltaic cells (solar panels) under Queensland jurisdictional arrangements. The arrangements allow distributors to recover the cost of the feed-in tariff through their network charges. Our distribution determination will address the feed-in tariff costs Ergon Energy and Energex are expected to incur in the next regulatory control period.

We understand Ergon Energy's request for us to address feed-in tariffs in the F&A relates to the potential spike in feed-in tariff costs early in the next regulatory control period. That is, actual feed-in tariff costs have been higher than estimated at the last Queensland distribution determination. The shortfall is corrected through an annual pass through allowance determined at the time of pricing approvals. However, the pass throughs are lagged by two years. This is because the actual feed-in tariff costs are not known until after the year in which they are incurred and can only be returned the subsequent year. In the first two years of the next regulatory control period, there will be an overlapping period where the historical pass through adjustment coincides with the introduction of more realistic feed-in tariff estimates for the next regulatory control period. The overlap will result in a significant increase in feed-in tariff related costs early in the next regulatory control period.

We may smooth year to year spikes in revenue requirements, subject to restrictions established by the rules. We have already indicated to the distributors our willingness to minimise adverse consumer impacts related to these specific items. However, until we know all of the costs of a regulatory proposal, we do not know the extent of any possible price smoothing. We will consider this issue as part of our distribution determination, which will also provide scope for stakeholder input.

⁴⁵³ www.business.qld.gov.au/industry/energy/electricity-industry/electricity-queensland/review-electricity-distributors

⁴⁵⁴ AER, *Final framework and approach paper – application of schemes – Energex and Ergon Energy 2010–15*, November 2008, p. 57.

Assets providing standard control, alternative control and unregulated services under transitional arrangements – Ergon Energy will liaise with us

Ergon Energy requested we clarify the treatment of assets used to provide standard control, alternative control and unregulated services under transitional arrangements.⁴⁵⁵ Under the previous Queensland jurisdictional arrangements, Ergon Energy and Energex recorded all of their assets in their RAB. When distributors used some of those assets to provide services other than standard control services, the additional revenues earned were subtracted from their approved regulated revenues. This prevented the distributors from recovering asset costs more than once. Under the transitional arrangements, this process has continued throughout the current regulatory control period.⁴⁵⁶

When the transitional arrangements end, the current approach to the RAB will no longer be consistent with the regulatory framework. Ergon Energy and Energex will be required to manage their RAB consistent with rule requirements. Under the rules, when an asset is established (purchased or constructed) the distributor should allocate its cost to the different types of services it provides—standard control, alternative control, negotiated or unregulated services.⁴⁵⁷ This cost allocation is done on the basis of the asset's expected future use to provide the different types of services. Only those asset costs allocated to standard control services may be included in the RAB.⁴⁵⁸ This cost allocation process is undertaken by each distributor according to its own cost allocation method (CAM)—a set of principles or policies, approved by us, describing how it will allocate costs to service types.⁴⁵⁹

To establish their respective RABs for the next regulatory control period, Ergon Energy and Energex must allocate their asset costs to service types according to an approved CAM.⁴⁶⁰ Because their current CAMs are consistent with the previous Queensland jurisdictional approach, we expect they will each submit a revised CAM to us for approval under the relevant NER provisions. An audit process will then verify that the RAB proposed by each distributor with its regulatory proposal has been established in accordance with its CAM.

Revenue adjustments for the carry forward of over-recovery or under-recovery of revenue – Ergon Energy will liaise with us

With its request that we replace the current F&A, Ergon Energy proposed we engage with it and Energex on how any over or under recovery of revenues from the current regulatory control period may be carried forward to the next. We have begun discussions with Ergon Energy and Energex on this issue. We will continue to liaise with the distributors on the existence and size of any over or under-recovery and how to manage them for the next regulatory control period. As this is an issue relevant to our distribution determination, we propose not to address this in the F&A.

⁴⁵⁵ Ergon Energy, *Submission on whether it is necessary or desirable to amend or replace the current framework and approach papers*, July 2013.

⁴⁵⁶ NER, clause 11.16.3

⁴⁵⁷ NER, Chapter 6, Part F.

⁴⁵⁸ NER, clause 6.5.1.

⁴⁵⁹ NER, clause 6.15.1.

⁴⁶⁰ NER, Chapter 6, Part F.