# 2016–17 Pricing Proposal

**Distribution services for 1 July 2016 to 30 June 2017**

Version 1.1 – For AER approval

# Revision history

| Version | Date | Summary of changes |
| --- | --- | --- |
| 1.0 | 29 April 2016 | Initial proposal to the AER for 2016–17. |
| 1.1 | 30 May 2016 | Reflection of deferral of introduction of excess kVAr charge for CACs until 1 July 2017 following advice from the AER that they have decided not to approve the charge as set out in our initial 2016–17 Pricing Proposal while they consider our 2017–2020 Tariff Structure Statement. |

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# 1 Introduction

## 1.1 Background

Ergon Energy Corporation Limited (Ergon Energy) is a Distribution Network Service Provider (DNSP) to around 730,000 customers in regional Queensland. Our service area covers around 97 per cent of Queensland and has approximately 160,000 kilometres of power lines and one million power poles. Around 70 per cent of our network's power lines are radial and service mostly rural areas with very low levels of customers per line kilometre.

## 1.2 Purpose

Clause 6.18.2(a)(2) of the National Electricity Rules (NER)[1] requires Ergon Energy to submit a Pricing Proposal to the Australian Energy Regulator (AER) at least two months before the commencement of the regulatory year.

The AER approves prices for services it classifies as Direct Control Services.[2] This Pricing Proposal assists the AER in approving these prices. It sets out how Ergon Energy's proposed tariffs and/or prices for Direct Control Services in 2016–17 meet the requirements of the NER.

Direct Control Services are separately classified into Standard and Alternative Control Services.

**Standard Control Services** are core distribution services associated with the access and supply of electricity to customers. They include network services (e.g. construction, maintenance and repair of the network), some connection services (e.g. small customer connections) and Type 7 metering services. Ergon Energy recovers our costs in providing Standard Control Services through network tariffs billed to retailers.

**Alternative Control Services** are comprised of:

- *Fee based services* – one-off distribution services that Ergon Energy undertakes at the request of an identifiable customer, retailer or appropriate third party which are levied as a separate charge, in addition to our Standard Control Services. These services are priced on a 'fixed fee' basis as the costs of providing the service (and therefore price) can be assessed in advance of the service being requested.

  Examples of fee based services include Type 5 and 6 meter installation and provision (on or after 1 July 2015) during business hours,[3] de-energisations, re-energisations and supply abolishment.
- *Quoted services* – similar to fee based services, but they are 'priced on application' as the nature and scope of these services are variable and the costs (and therefore price) are specific to the individual requestor's needs (e.g. design and construction of connection assets for major customers, real estate development connections and special meter reads etc.).[4]
- *Default Metering Services* – relate to:
  - Type 5 and 6 meter installation and provision (before 1 July 2015)
  - Type 5 and 6 meter installation and provision (on or after 1 July 2015), where the replacement meter is initiated by Ergon Energy as a DNSP

[1] Version 65.
[2] NER 6.1.3(b9)(2).
[3] Where the new or upgraded meter is required as a result of a customer request.
[4] The prices set out in this Pricing Proposal are examples of potential prices for quoted services.

  - Type 5 and 6 metering maintenance, reading and data services.

  Ergon Energy recovers our costs of providing Default Metering Services through daily capital and non-capital charges based on the number and type of meters we provide the customer.  These charges are billed to retailers.

- *Public Lighting Services* – relate to the provision, construction and maintenance of public lighting assets owned by Ergon Energy, and emerging public lighting technology.  Ergon Energy recovers our costs of providing Public Lighting Services through a daily public lighting charge billed to retailers.  We also charge a one-off exit fee, when a customer requests the replacement of an existing public light for a light emitting diode (LED) luminaire before the end of its useful life.[5]

The tariff schedules for our Standard Control Services are set out in Appendix 1 and Appendix 2, and, for our Alternative Control Services, in Appendix 4.

## 1.3 Structure

This Pricing Proposal is structured as follows:

- Part 1 provides an overview of Ergon Energy's pricing arrangements and approach to setting prices for both Standard Control Services and Alternative Control Services.  It includes:
  - an overview of the context in which we develop prices, including the relationship with the regulatory framework and our Tariff Structure Statement (TSS)
  - an explanation of the revenues we are required to recover through prices in 2016–17 for Standard Control Services.
- Part 2 details how this Pricing Proposal satisfies the requirements of the NER and the AER's Distribution Determination.

A series of appendices provide further information on our revenue and price calculations, including models and expected price trends.

In accordance with the AER's Confidentiality Guideline, Ergon Energy has provided both public and confidential versions of our Pricing Proposal, where required.  Our confidentiality claims, including the proportion of confidential material contained within our Pricing Proposal and its attachments and appendices, are set out in Attachment 1.  All confidential information in the public documents has been redacted.

## 1.4 Supporting network pricing documents

In addition to this Pricing Proposal, Ergon Energy has a number of network pricing documents to assist network users, retailers and interested parties understand the development and application of tariffs and connection charges.  The documents outlined in Figure 1.1 below provide further information about network tariffs – including tariff assignment, Network Tariff Codes and loss factors – and operational issues relating to Standard and Alternative Control Services.[6]

The *Network Tariff Guide* and the *Price List for Alternative Control Services* will also set out the tariffs and prices for 2016–17 and any other changes that are required as a result of this Pricing Proposal, once approved.

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[5] Outside of our LED transition program.

[6] These documents will be available on Ergon Energy's website at: www.ergon.com.au/network/network-management/network-pricing.

**Figure 1.1: Supporting network pricing documentation**

**Tariff Structure Statement**

- Sets out the proposed tariff structures for the 2017 to 2020 period
- Details how the proposed tariff structures comply with the pricing principles
- Describes the tariff-setting process for Standard and Alternative Control Services
- Provides details on the assignment of customers to tariff classes and tariffs
- To be approved by the AER in early 2017, following stakeholder consultation

**Information Guide for Standard Control Services Pricing**

- Sets out the basis upon which Ergon Energy's revenue cap for Standard Control Services is recovered from various customer groups through network tariffs
- Provides a description of the network tariffs
- Published annually

**Network Tariff Guide**

- An operational document for customers, retailers and consultants, setting out the Network Tariff Codes and application rules and rates for each Network Tariff Code
- Applies to network users connected to Ergon Energy's regulated distribution network
- Published annually, and updated as required

**Price List for Alternative Control Services**

- Sets out Ergon Energy's Alternative Control Services and the prices that apply for fee based services, Default Metering Services and Public Lighting Services
- Published annually, and updated as required

**Connection Policy**

- Sets out when a connection charge may be payable by retail customers or real estate developers and the aspects of the connection service for which a charge may be applied
- Details how Ergon Energy calculates the capital contribution to be paid
- Approved by the AER in 2015 as part of the Distribution Determination

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# PART 1 – APPROACH TO PRICE SETTING

# 2 Approach to price setting

## 2.1 Regulatory framework

As a DNSP, Ergon Energy is subject to economic regulation by the AER under the National Electricity Law (the Law) and the NER. Under the Law and NER, the AER is responsible for regulating the revenues Ergon Energy can earn, and the prices that Ergon Energy can charge for certain services provided by means of, or in connection with, our distribution system.

### 2.1.1 Distribution Determination

On 29 October 2015, the AER made its Distribution Determination for regulated distribution services provided by Ergon Energy.[7] The Distribution Determination effectively sets the revenue and pricing control regime that Ergon Energy must comply with over the current regulatory control period (i.e. 2015–20) for these services.

It also details how Ergon Energy must report on the recovery of jurisdictional scheme amounts. For Ergon Energy, this includes:

- feed-in tariff (FiT) payments made under the Queensland Government's Solar Bonus Scheme
- the energy industry levy payable under our Distribution Authority.

### 2.1.2 Tariff Structure Statement

In November 2014, amendments to the NER fundamentally changed the framework in which tariffs for Direct Control Services are developed. Included in these changes were new obligations for DNSPs, including Ergon Energy, to develop prices that better reflect the costs of providing services to customers so they can make informed decisions about how they use electricity.

As part of this new framework, Ergon Energy submitted a TSS to the AER on 27 November 2015. The TSS sets out our proposed tariff structures for the 2017 to 2020 period and how we have applied the new pricing principles in developing these structures.

The TSS does not apply in 2016–17. However, we have established 2016–17 as our foundation year, since all of our major reforms are expected to be in place for the beginning of this pricing year. We plan to keep our tariff structures relatively stable out to 2020 to build a greater understanding of the new tariff options and promote their benefits. On this basis, much of the content in our TSS around adherence to the pricing principles and tariff development is directly relevant to our 2016–17 prices and this Pricing Proposal. Several sections of this Pricing Proposal therefore refer to the TSS for further information.

### 2.1.3 Queensland Government cap on fee based and quoted services

The Queensland Government has historically set maximum price caps to apply to a subset of Ergon Energy's services through Schedule 8 of the *Electricity Regulation 2006*. Since the price caps are imposed through legislation, they take precedence over the prices approved by the AER. This means Ergon Energy cannot recover our full costs of providing these services and the shortfall is borne by us.

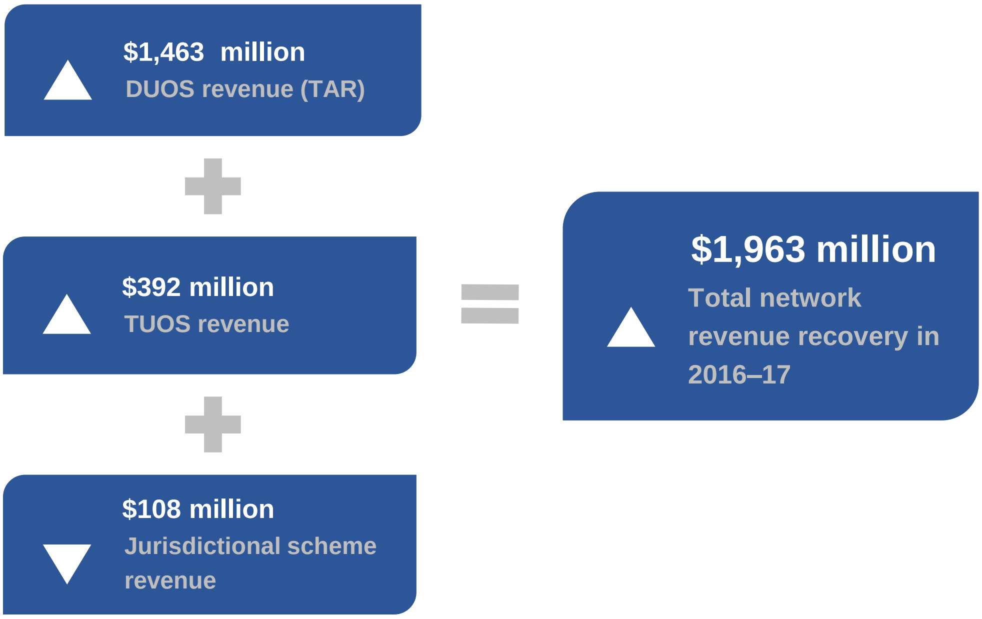
It is important to note that the prices contained in Appendix 4 reflect the tariffs derived under the tariff-setting process and, depending on the type of service, the prices in Appendix 4 may be higher

[7] This Distribution Determination replaces the preliminary decision released by the AER on 30 April 2015. The preliminary decision was used to set prices for 2015–16.

than the prices customers will be charged. The *Price List for Alternative Control Services* will provide the rates applicable for 2016–17 as a result of Schedule 8 maximum price caps, and hence the prices customers will be charged.

## 2.2 Revenue recovery

In 2016–17, the total network revenue that Ergon Energy will need to recover from network users is approximately $1,963 million.




The amount to be recovered includes Ergon Energy's Total Annual Revenue (TAR) of approximately $1,463 million. This is 1.32 per cent above what we expected to recover from network users in 2015–16.

The TAR reflects Ergon Energy's smoothed expected revenue for 2016–17 plus other annual revenue adjustments. The smoothed expected revenue is determined by taking the smoothed expected revenue for 2015–16 and adjusting it by:

- an annual percentage change in inflation of 1.69 per cent. This is lower than the annual percentage change in inflation that applied in 2015–16 (2.55 per cent)
- a revised X factor, which takes into account an updated return on debt figure for 2016–17 of 5.06 per cent.[8] This is higher than the return on debt figure that applied in 2015–16 (5.01 per cent)
- the s-factor for 2016–17, which relates to our performance under the Service Target Performance Incentive Scheme (STPIS) in 2014–15.[9] This is effectively a negative revenue adjustment.

The other revenue adjustments that will apply in 2016–17 relate to:

- a Distribution Use of System (DUOS) under recovery in 2014–15 (**+** *positive revenue adjustment*)
- an under recovery of capital contributions in 2014–15 (**+**)

[8] Under the trailing average portfolio approach, the return on debt, and consequently, the allowed rate of return, will vary each regulatory year. As such, the Post Tax Revenue Model (PTRM) and the smoothed revenue requirement are amended each year to take into account these updated figures. The AER provided an amended PTRM on 23 March 2016.

[9] The s-factor also takes into account a banked amount from 2015–16 and the removal of the prior year's s-factor impact.

- an over recovery of shared assets revenue in 2014–15 (**–** *negative revenue adjustment)*
- a cost pass through amount associated with FiT payments made under the Solar Bonus Scheme in 2014–15 (**+**)
- a carryover amount associated with the Demand Management Incentive Scheme (DMIS) that operated in the regulatory control period 2010–15 (**–**).

A detailed discussion on the calculation of the revenue cap is contained in Section 4.5 of this Pricing Proposal.

Ergon Energy also recovers revenue on behalf of Powerlink and other designated pricing proposal charges (see Section 4.12), and jurisdictional scheme revenue associated with the Solar Bonus Scheme and the energy industry levy (see Section 4.13).

## 2.3 Establishing tariffs for Standard Control Services

Appendix F of our TSS sets out the process we undertake each year to establish our network tariffs.

In 2016–17, we have applied the tariff classes and tariff structures detailed in Chapter 4 of our TSS.[10] These structures largely reflect those applying in 2015–16. However, we are proposing some amendments to each customer group. These changes are outlined in Table 2.1 below, with further information available in Section 6.3.3.

In addition to the normal year-on-year variability of tariff rates (e.g. due to movements in the TAR and changes in customer numbers, energy and demand), some changes have been necessary in 2016–17 to better reflect the Long Run Marginal Cost (LRMC). Table 2.1 highlights the tariffs that are impacted by this process and the affected charge and/or charging parameter.

ICC tariffs are site-specific, reflecting the individual customer's circumstances. The cost allocation process for ICCs is set out in our *Information Guide for Standard Control Services.*

**Table 2.1: Revenue recovery and structural changes since 2015–16, by impacted tariff**

| Tariff | Structural changes | LRMC recovery | Residual recovery |
|---|---|---|---|
| *Standard Asset Customer (SAC) Small* | | | |
| Inclining Block Tariff (IBT) | • Nil | • Changed the first consumption block to a positive rate, to progressively reflect the value of the low voltage LRMC | • Consistent with the revenue allocation process set out in Appendix F of the TSS (legacy tariff structures) |
| Residential and Business Seasonal Time-of-Use Energy (STOUE) | • Consolidated the shoulder energy charge (including time periods) into the peak energy charge | • Applied the LRMC rate over a longer period of time<br>• Increased the peak energy rates to reflect a greater proportion of the LRMC | • Consistent with the revenue allocation process set out in Appendix F of the TSS (legacy tariff structures) |

10 The exception being the Demand Controlled tariff. Ergon Energy has decided not to introduce this tariff in 2016–17.

| Tariff | Structural changes | LRMC recovery | Residual recovery |
|---|---|---|---|
| Residential and Business Seasonal Time-of-Use Demand (STOUD) | • Amended and aligned the methodology used to calculate both the peak and off-peak demand charges | • Increased the peak demand charge rates to reflect a greater proportion of the LRMC | • Consistent with the revenue allocation process set out in Appendix F of the TSS (cost reflective tariff structures) |
| *SAC Large* | | | |
| STOUD | • Nil | • Increased the peak demand charge rates to reflect a greater proportion of the LRMC | • Consistent with the revenue allocation process set out in Appendix F of the TSS (cost reflective tariff structures) |
| *Connection Asset Customer (CAC)* | | | |
| CAC any time demand | • Nil | • Increased the demand charge rates to reflect a greater proportion of the LRMC | • Consistent with the revenue allocation process set out in Appendix F of the TSS (legacy tariff structures) |
| CAC STOUD | • Amended the calculation of the peak demand charge<br>• Amended the calculation and period of application of the capacity charge | • Increased the demand charge rates to reflect a greater proportion of the LRMC | • Consistent with the revenue allocation process set out in Appendix F of the TSS (cost reflective tariff structures) |

Appendix 1 and Appendix 2 set out the tariffs for Standard Control Services that apply in 2016–17.

Where a tariff class includes both a legacy and optional tariff, Ergon Energy develops rates for the tariffs by:

- calculating the rates for the optional tariff assuming full transition to the optional tariff
- using a sample of customers, calculating the range of customer impacts of moving to the optional tariff and the level of churn possible
- determining the rates for the legacy tariff based on the assumed take up of the optional tariff.

Our optional tariffs are designed in a way which we hope incentivises more customers to transition to them.

In future years, rates for volume-based and optional, demand-based tariffs will be calculated simultaneously. As part of this progression, we have applied this approach for CAC tariffs in 2016–17.

## 2.4 Establishing tariffs for Alternative Control Services

Ergon Energy's Alternative Control Services are regulated under a price cap control mechanism. This means the AER determines Ergon Energy's efficient costs, and approves a maximum price (or schedule of rates) that Ergon Energy can charge for the service.

Appendix G of our TSS sets out the process we undertake each year to establish our prices for Alternative Control Services. The approach to setting tariffs varies for each type of Alternative Control Service:

- For our fee based services, we have calculated a cost build-up price using the quoted services formula and a capped price using the fee based ancillary network services formula set out in the Distribution Determination. The prices presented in this Pricing Proposal for each fee based service are the lower of these two amounts.
- For our quoted services, we have used the quoted services formula to develop illustrative prices. This formula will also be used in practice to develop actual prices for quoted services.
- For our Default Metering Services and Public Lighting Services, we have applied the relevant price cap formulae specified in the Distribution Determination. The exception to this is the public lighting exit fees, which have been escalated by inflation only.

The calculation of Ergon Energy's Alternative Control Service prices, including our compliance with the price cap control mechanism, is provided in Appendix 5. Various cost inputs used in the calculation of our fee based and quoted services have been updated. These changes are discussed in Section 5.3.

Appendix 4 sets out the 2016–17 tariffs for our Alternative Control Services. In relation to each quoted service, it is important to note that the prices provided in Appendix 4 are examples only. This is because the actual prices for quoted services will be determined at the time of the requestor's enquiry and will reflect the actual requirements of the service being requested.

# PART 2 – DEMONSTRATING COMPLIANCE

# 3 Compliance matrix

The matters that must be satisfied by the publication of this Pricing Proposal are outlined in rule 6.18 of the NER.[11] This includes a requirement on Ergon Energy to demonstrate compliance with the NER and any applicable Distribution Determination.[12]

Ergon Energy's compliance with these requirements is set out in the following chapters. We have addressed Standard Control Services (including Transmission Use of System (TUOS) charges and jurisdictional schemes) and Alternative Control Services separately.

For ease of reference, a summary matrix of the obligations and how we have demonstrated compliance is provided in Appendix 7.

[11] Version 65.
[12] NER, clause 6.18.2(b)(7).

# 4 Standard Control Services

## 4.1 Tariff classes

For 2016–17, Ergon Energy's selection of Standard Control Service tariff classes aligns with our cost allocation process for tariff-setting by differentiating between:

- customer groups
  - Individually Calculated Customers (ICCs)
  - Connection Asset Customers (CACs)
  - Standard Asset Customers (SACs)
    - SAC Large
    - SAC Small
    - SAC Unmetered
  - Embedded Generators (EGs)
- locational zones
  - East Zone
  - West Zone
  - Mount Isa Zone.

There are 18 tariff classes for Standard Control Services, as shown in Table 4.1 below.[13]

**Table 4.1: Ergon Energy's Standard Control Service tariff classes**

| Customer group | East Zone | West Zone | Mount Isa Zone |
|---|---|---|---|
| ICC | ● | ● | ● |
| CAC | ● | ● | ● |
| EG | ● | ● | ● |
| SAC Large | ● | ● | ● |
| SAC Small | ● | ● | ● |
| SAC Unmetered | ● | ● | ● |

In accordance with clause 6.18.3(b) of the NER, all of Ergon Energy's customers for Standard Control Services are a member of one or more tariff classes. This is because:

- all of Ergon Energy's customers are assigned to at least one network tariff in the Distribution Cost of Supply (DCOS) Model, and no customers are priced outside this model
- all network tariffs calculated by the DCOS Model are allocated to Standard Control Service tariff classes (Standard Control Services being a subset of Direct Control Services).

Consistent with clause 6.18.3(c) of the NER, Ergon Energy assigns customers receiving Standard Control Services to one of the tariff classes shown in Table 4.1. Separately, Ergon Energy provides tariff classes for customers seeking Alternative Control Services, as demonstrated in Section 5.1.

13 NER, clauses 6.18.2(b)(1) and 6.18.3(a).

Finally, clause 6.18.3(d) of the NER requires that a tariff class be constituted with regard to the need to group customers together on an economically efficient basis, and the need to avoid unnecessary transactions costs. This requires a balance to be struck between:

- setting tariff classes and tariffs that send efficient signals to customers – which, in principle, will vary according to each individual customer's size, consumption pattern/profile and location/feeder within the network, and
- minimising the costs of developing and implementing a large number of bespoke tariff classes and tariffs.

Our pricing methodologies are developed according to the principle that network tariffs are an equitable reflection of the network user's utilisation of the existing network, while minimising the inefficiency of price averaging. This approach helps ensure customers with broadly similar characteristics, who impose similar costs on the network, are classed together so that they face similar tariff structures.

Our tariff class groupings follow the process of revenue allocation consistent with these principles. The tariffs within each tariff class have been grouped together in a manner that is easy for customers and retailers to understand, which avoids unnecessary transaction costs.

## 4.2 Tariff charging parameters

A tariff represents a combination of charges that Ergon Energy applies to a customer (through their retailer) in order to recover network costs. Within each tariff class, a number of tariffs can be offered.

Tariffs have three key defining characteristics:

- the charge (can also be called a 'charging component', 'tariff component' or 'tariff element')
- the parameters of the charge (specific characteristics that relate to the charge that influence how it is calculated)
- the rate applied to each charge.

Each tariff has at least one charge, but usually has more than one. Ergon Energy uses six broad types of charges and eight charging parameters for our Standard Control Services, as shown in Table 4.2.

Each charge and charging parameter is selected and structured to provide signals to network users about the efficient use of the network. This is particularly the case for the optional, LRMC-based tariffs. The charges and charging parameters that have been adopted in 2016–17 for each tariff are shown in Appendix 1 and 2, with further information available in Chapter 4 of the TSS.

**Table 4.2: Types of charges and charging parameters**

| Charge | Charging parameter | Application to tariffs |
|---|---|---|
| Fixed charge | Represented as a rate ($) per day or rate ($) per day per device. | Applies to all tariffs except:<br>• Residential STOUD<br>• Business STOUD<br>• CAC STOUD. |
| Volume charge | Represented as a rate ($) per kWh. Different parameters apply to this charge for different tariffs. Within a tariff structure, volume charge rates can be flat or be applied to different blocks (based on consumption) or times (peak and off-peak). | Applies to all tariffs except EGs. |
| Demand charge | Represented as either a rate ($) per kW or a rate ($) per kVA. Different parameters apply to this charge for different tariffs. Within a tariff structure, demand charge rates can be:<br>• applied year round or seasonally (with different peak and off-peak rates)<br>• calculated based on:<br>○ a single period in the month<br>○ the maximum demand within a peak demand window<br>○ an average of demands within a demand window.<br>Some tariff structures include a floor (the demand charge must include at least the rate times 'X' demand) or a threshold (the demand charge is only calculated for demands recorded above a particular level). | Applies to all tariffs except:<br>• Residential IBT<br>• Business IBT<br>• Residential STOUE<br>• Business STOUE<br>• Controlled load<br>• Unmetered supplies<br>• EGs. |
| Capacity charge | Represented as a rate ($) per kVA. | Applies to the following tariffs:<br>• CAC any time demand tariffs<br>• CAC STOUD<br>• ICC site-specific tariffs. |
| Excess reactive power charge | Represented as a rate ($) per excess kVAr. | Applies to the following tariffs:<br>• ICC site-specific tariffs. |
| Connection unit charge | Represented as a rate ($) per connection unit per day. | Applies to the following tariffs:<br>• CAC any time demand tariffs<br>• CAC STOUD. |

## 4.3 Assigning and reassigning customers to tariff classes

Attachment 14 of the Distribution Determination outlines the general procedures Ergon Energy must comply with when assigning or reassigning customers to tariff classes. Consistent with these procedures, Ergon Energy has developed a more detailed document containing our tariff class assignment and reassignment criteria for Standard Control Services, notification process and objections process (refer to Appendix H of our TSS). Ergon Energy will comply with these procedures in 2016–17.

In addition, Attachment 14 of the Distribution Determination requires Ergon Energy's Pricing Proposal to set out a method of how we will review and assess the basis on which a customer is charged, where the charging parameters for a particular tariff result in a basis of charge that varies according to the customer's usage or load profile. Ergon Energy's compliance with this requirement for Standard Control Service tariff classes is set out below.

### 4.3.1 Review of the charging basis

Ergon Energy may review the charging basis where:

- a change in the usage, load profile or customer classification (i.e. business or residential for SAC Small customers) of a customer may mean a different network tariff is more applicable, or
- within a network tariff, it is appropriate to change the charging parameter(s) because of changes relating to the customer's usage. For example, an additional charge and charging parameter may be applicable once usage reaches a certain level.

Ergon Energy annually reviews the assignment of customers to our tariff classes as part of the process of developing and submitting our Pricing Proposal to the AER for approval. In undertaking this review, Ergon Energy uses set procedures and specific criteria to determine when it is appropriate for a customer to be reassigned to a different tariff class as a result of a material change in the customer's energy consumption or connection characteristics (refer to Appendix H of our TSS). These procedures, in conjunction with the classification of SAC Small customers as business or residential, also ensure the customer's underlying network tariff associated with a tariff class remains appropriate.

In addition to this annual review process, customers and/or retailers can expressly request Ergon Energy to review and change a network tariff assigned to a customer in the event of variation to the customer's usage, load profile or classification as a business or residential customer. Provided Ergon Energy agrees to the change in network tariff, this change can take effect during a regulatory year. Further information on network tariff reviews is contained in Appendix H of our TSS.

With respect to variations in the basis of charge within a network tariff, Ergon Energy notes that the structure and rates of each charge and charging parameter within a tariff (see Table 4.2) apply equally to each customer assigned to the network tariff, regardless of a customer's individual usage or load profile. However, the actual network charges applied to customers may vary.

For example, the actual network charges applied to SAC Small customers on an IBT will vary according to their level of usage. Similarly, for customers on Time-of-Use (TOU) tariffs, the network charges will vary according to when their usage (demand or energy, depending on the tariff) occurs. For our ICCs, the excess kVAr charge may apply to customers with a poor power factor.

Should a customer's usage or load profile vary, the customer can either manage their usage by responding to the price signals inherent in the charges and charging parameters of the tariff, or request to be reassigned to an alternative network tariff (if applicable) that may be more cost-effective for the customer's revised requirements.

## 4.4 Tariff schedules

Clause 6.18.2(b)(2) of the NER requires Ergon Energy to set out the proposed tariffs for each tariff class. Accordingly, the 2016–17 tariffs for Standard Control Services are set out in Appendix 1 and Appendix 2.

## 4.5 Revenue is consistent with TAR formula

Attachment 14 of the Distribution Determination requires Ergon Energy to demonstrate in our Pricing Proposal that our revenue is consistent with the TAR formula.

### 4.5.1 Calculation of the TAR

In accordance with Figure 14.1 of Attachment 14 of the Distribution Determination, Ergon Energy applies the following formulae when calculating the smoothed expected revenue and the TAR for a given regulatory year:

1. $TAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$ i = 1,...,n and j = 1,...,m and t = 1,...,5

2. $TAR_t = AR_t + I_t + B_t + C_t$ t = 1, 2..., 5

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

Where:

$TAR_t$ is the total annual revenue in year t.

$p_t^{ij}$ is the price of component ‘j’ of tariff ’i' in year t.

$q_t^{ij}$ is the forecast quantity of component ‘j’ of tariff ‘i' in year t.

$AR_t$ is the annual smoothed expected revenue for regulatory year t. For the first year of the 2015–20 regulatory control period, this amount will be equal to the smoothed revenue requirement for 2015–16 set out in the PTRM.

$I_t$ is the final carryover amount from the application of the DMIS from the 2010–15 distribution determination. This amount will be calculated using the method set out in the DMIS and deducted from/added to allowed revenue in the 2016-17 pricing proposal.

$B_t$ is the sum of:

- any under or over recoveries relating to capital contributions and shared assets from 2013–14 and 2014–15
- any under or over recovery of actual revenue collected through DUOS charges in regulatory year t–2 as calculated using the method in appendix A [of Attachment 14 of the Distribution Determination].

$C_t$ is the sum of adjustments related to:

- feed-in tariff pass through amounts relating to the 2013–14 and 2014–15 regulatory years
- any AER approved cost pass through amounts during the 2015–20 regulatory control period.

$\Delta CPI_t$ is the annual percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index (CPI) All Groups, Weighted Average of Eight Capital Cities from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

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

For example, for the 2015–16 year, t–2 is December quarter 2013 and t–1 is December quarter 2014 and in the 2016–17 year, t–2 is December quarter 2014 and t–1 is December quarter 2015 and so on.

$X_t$ is the X factor for each year of the 2015–20 regulatory control period as determined in the PTRM, and annually revised for the return on debt update in accordance with the formula specified in Attachment 3 – rate of return [of the Distribution Determination] – calculated for the relevant year.

$S_t$ is the s-factor determined in accordance with the STPIS for regulatory year t.

The resulting revenue cap for 2016–17, and the underlying calculations, is provided in Appendix 2. Ergon Energy confirms that the expected revenue to be collected from our DUOS charges is less than the TAR.

### 4.5.2 DUOS unders and overs account

Under a revenue cap, our revenues are adjusted annually to clear any under or over recovery of actual revenue collected through DUOS charges. This 'unders and overs' rebalancing process is undertaken as part of annual pricing to ensure we recover no more and no less than the TAR approved by the AER for any given year.

Under these arrangements there is generally a two year lag between the year in which the DUOS under or over recovery occurs and the year in which adjustments are made to prices to 'clear' the under or over recovery. For example, for prices set in 2016–17, the adjustment will relate to actual under or over recoveries in the 2014–15 regulatory year.

Appendix A of Attachment 14 of the Distribution Determination requires Ergon Energy to maintain a DUOS unders and overs account, which is to be provided to the AER in this Pricing Proposal. This account is set out in Table 4.3 below.

**Table 4.3: Calculation of DUOS unders and overs account ($'000)**

| | 2014-15 Year t-2 (actual) | 2016-17 Year t (forecast) |
|---|---|---|
| **(A) Revenue from DUOS charges** | $1,776,360 | $1,463,200 |
| **(B) Less TAR for regulatory year =** | $1,838,309 | $1,463,200 |
| + Annual revenues ($AR_t$) | $1,605,442 | $1,157,524 |
| + DMIS carryover amount ($I_t$) | $0 | ($2,576) |
| + Sum of under or over recoveries ($B_t$) = | $148,847 | $180,184 |
| + *Capital contributions/shared assets* | *$61,308* | *$108,129* |
| + *DUOS revenue under/over recovery approved* | *$87,539* | *$72,055* |
| + Sum of pass through adjustments ($C_t$) = | $84,020 | $128,068 |
| + *Feed-in tariff cost pass throughs* | *$84,020* | *$128,068* |
| + *Approved pass through amounts* | *$0* | $0 |
| **(A minus B) Under/over recovery of revenue for regulatory year** | ($61,949) | $0 |
| <u>**DUOS unders and overs account**</u> | | |
| Nominal WACC t-2 (per cent) | 9.72% | |
| Nominal WACC t-1 (per cent) | 6.01% | |
| Opening balance | $0 | ($72,055) |
| Interest on opening balance for 1 regulatory year | $0 | n/a |
| Under/over recovery of revenue for regulatory year | ($61,949) | $72,055 |
| Interest on under/over recovery for 2 regulatory years | ($10,106) | n/a |
| **Closing balance** | ($72,055) | $0 |

## 4.6 Forecast weighted average revenue for each tariff class

Clause 6.18.2(b)(4) of the NER requires Ergon Energy to set out, for each tariff class related to Standard Control Services, the expected weighted average revenue for the relevant regulatory year and also for the current regulatory year. This is shown in Appendix 3.

## 4.7 Side constraints

Clause 6.18.6(b) of the NER requires the expected weighted average revenue to be raised from a Standard Control Service tariff class to not exceed the corresponding expected weighted average revenue from the preceding year by more than a permissible percentage (side constraint).

The AER provides further guidance on side constraints in Attachment 14 of the Distribution Determination. Ergon Energy must demonstrate that the proposed DUOS prices meet the following side constraints formula:

$$\frac{(\sum_{i=1}^{n}\sum_{j=1}^{m} d_t^{ij} q_t^{ij})}{(\sum_{i=1}^{n}\sum_{j=1}^{m} d_{t-1}^{ij} q_t^{ij})} \leq (1+\Delta CPI_t)\times(1-X_t)\times(1+2\%)\times(1+S_t)+I_t^{'}+B_t^{'}+C_t^{'}$$

where each tariff class has "n" tariffs, with each up to "m" components, and where:

$d_t^{ij}$ is the proposed price for component 'j' of tariff 'i' for year t.

$d_{t-1}^{ij}$ is the price charged for component 'j' of tariff 'i' in year t–1.

$q_t^{ij}$ is the forecast quantity of component 'j' of tariff 'i' in year t.

$\Delta CPI_t$ is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1

divided by

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2

minus one.

For example, for the 2015–16 year, t–2 is December quarter 2013 and t–1 is December quarter 2014 and in the 2016–17 year, t–2 is December quarter 2014 and t–1 is December quarter 2015 and so on.

$X_t$ is the X factor for each year of the 2015–20 regulatory control period as determined in the PTRM, and annually revised for the return on debt update in accordance with the formula specified in Attachment 3 – rate of return [of the Distribution Determination] – calculated for the relevant year. If X>0, then X will be set equal to zero for the purposes of the side constraint formula.

$S_t$ is the s-factor determined in accordance with the STPIS for regulatory year t.

$I_t^{'}$ is the annual percentage change from the final carryover amount from the application of the DMIS from the 2010–15 distribution determination. This amount will be deducted from/added to allowed revenue in the 2016–17 pricing proposal.

$B_t^{'}$ is the annual percentage change from the sum of:

- any under or over-recoveries relating to capital contributions and shared assets from 2013–14 and 2014–15
- any under or over recovery of actual revenue collected through DUOS charges in regulatory year t–2 as calculated using the method in appendix A [of Attachment 14 of the Distribution Determination].

$C_t^{'}$ is the annual percentage change from the sum of adjustments related to:

- feed-in tariff pass through amounts relating to 2013–14 and 2014–15
- amounts relating to the occurrence of any of the prescribed and nominated cost pass through events.

Ergon Energy confirms that the weighted average revenue of our tariff classes for 2016–17 is within the percentage allowed by the side constraint formula (i.e. 24.58 per cent). This is demonstrated in Appendix 2.

## 4.8 Avoidable and stand alone costs

Clause 6.18.5(a) of the NER requires that for each tariff class, the revenue expected to be recovered must lie on or between an upper bound representing the stand alone cost of serving the customers who belong to that class and a lower bound representing the avoidable cost of not serving those customers.

The NER do not specifically define stand alone and avoidable costs or set out the methodology that should be applied to calculate these costs. Consequently, Ergon Energy interprets these costs in the following manner:

- **Stand alone costs** for a tariff class are the costs of establishing and maintaining infrastructure to service a single tariff class as if no other tariff classes needed to be served. They represent the upper bound costs of providing a service for a particular tariff class. Assuming that no other tariff classes use network infrastructure means that the economies of scale and scope from using a shared network to serve customers across multiple tariff classes are ignored.
- **Avoidable costs** are the costs which would be avoided by Ergon Energy not providing a distribution service to a particular tariff class, assuming all other tariff classes continued to be served. Therefore, if Ergon Energy was to cease providing services to CACs in our West Zone, the avoidable cost methodology assesses the extent to which our costs would be reduced as a result.

Our approach to determining these costs for our Standard Control Services is described in the following sections.

### 4.8.1 Stand alone costs

Ergon Energy has revised our estimate of the stand alone costs for each tariff class by calculating the total annual costs of operating the network, less the cost of serving all other tariff classes. This approach uses the revenue cap as the first step, which is allocated to tariffs using the DCOS Model.

Ergon Energy's assessment of the stand alone cost was determined from a review of the network in response to the following question:

> *If only one tariff grouping XX is supplied, what assets would be required to supply only this tariff grouping? If only these assets are required, what revenue should be collected?*

Ergon Energy's assessment of the stand alone cost was based on our DCOS Model. The network is assumed to remain in its current state with supply voltages unchanged. Individual classes of assets and their associated costs are 'optimised' by removing a proportion, while still notionally providing the necessary capacity to supply just the tariff grouping concerned. We have made some slight refinements in our approach to this estimation in 2016–17.

The estimated stand alone costs for groupings of similar Standard Control Service tariff classes (e.g. high voltage connected customers) are, in effect, the portion of the revenue cap that could be avoided if all other tariff groupings were not served.

### 4.8.2 Avoidable costs

To determine the avoidable costs of each grouping of similar tariff classes, Ergon Energy used a similar approach to the stand alone calculation, based on the DCOS Model and its allocation of the revenue cap. In this case, the cost was determined in response to the following question:

> *If the XX tariff grouping was not connected to the network, what assets would not be required? If these assets are not required, what revenue should not be collected?*

Again, the network is assumed to remain in its current state with supply voltages unchanged. Individual classes of assets and their associated costs from the DCOS Model are 'optimised' by removing a proportion, as the demand is notionally reduced for each tariff grouping not supplied, while still maintaining the same standard of network service to be maintained to all remaining tariff groupings.

As with the stand alone costs, Ergon Energy has determined the avoidable costs for groupings of similar Standard Control Service tariff classes by estimating the notional portion of the revenue cap that could be avoided, if the tariff grouping under consideration was not served.

### 4.8.3 Comparison of avoidable costs, expected revenue and stand alone costs

Table 4.4 below demonstrates that, for each Standard Control Service tariff class containing retail customers, the 2016–17 expected revenue for each tariff class lies on or between the lower bound avoidable cost and an upper bound stand alone cost, in accordance with clause 6.18.5(a) of the NER.

The calculation of these amounts is demonstrated in Appendix 2.

**Table 4.4: Avoidable costs, expected revenue and stand alone costs for Standard Control Services (GST Exclusive)**

| Tariff class | Avoidable costs | Expected revenue | Stand alone costs | Clause 6.18.5(a) met |
|---|---|---|---|---|
| ICC – East | $20,638,779 | $39,702,415 | $268,324,915 | Yes |
| ICC – West | $2,067,121 | $13,822,956 | $31,498,685 | Yes |
| ICC – Mount Isa | $0 | $0 | $0 | Yes |
| CAC – East | $27,785,676 | $81,441,576 | $291,069,966 | Yes |
| CAC – West | $359,222 | $10,986,318 | $29,676,901 | Yes |
| CAC – Mount Isa | $0 | $0 | $0 | Yes |
| SAC Large (>100 MWh p.a.) – East | $198,049,197 | $316,055,456 | $1,058,583,373 | Yes |
| SAC Large (>100 MWh p.a.) – West | $53,287,928 | $86,055,625 | $290,455,452 | Yes |
| SAC Large (>100 MWh p.a.) – Mount Isa | $3,972,076 | $4,558,554 | $14,400,336 | Yes |
| SAC Small (<100 MWh p.a.) – East | $334,713,218 | $677,514,001 | $1,058,583,373 | Yes |
| SAC Small (<100 MWh p.a.) – West | $110,217,029 | $197,865,198 | $290,455,452 | Yes |
| SAC Small (<100 MWh p.a.) – Mount Isa | $6,618,200 | $10,680,168 | $14,400,336 | Yes |
| SAC Unmetered – East | $7,463,760 | $18,395,701 | $615,129,543 | Yes |
| SAC Unmetered – West | $2,047,916 | $2,681,502 | $29,440,559 | Yes |
| SAC Unmetered – Mount Isa | $102,158 | $312,679 | $776,728 | Yes |

## 4.9 Long Run Marginal Cost

In late 2014, the Australian Energy Market Commission (AEMC) made a suite of changes to the NER that modified the pricing principles in clause 6.18.5.[14] Amongst other things, these changes increased the weight placed on the LRMC in setting tariffs. Previously, the NER required that each tariff, and if it consisted of two or more charging parameters, each charging parameter, "take into account" the LRMC for the service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates.[15]

The pricing principles in clause 6.18.5(f) of the NER now require each tariff to be "based on" the LRMC of providing the service to retail customers assigned to that class, with:

- the method of calculating such costs, and
- the manner in which that method is applied

to be determined having regard to:

- the costs and benefits associated with calculating, implementing and applying the method

[14] AEMC (2014), *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 No 9*, 27 November 2014. Refer to http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements.
[15] NER, clause 6.18.5(b)(1).

- the additional costs likely to be associated with meeting (incremental) demand from the customers that are assigned to the tariff at times of greatest utilisation for the relevant part of the distribution network
- the location of customers that are assigned to that tariff and the extent to which costs vary between different locations.

To the extent that tariffs based on the LRMC do not recover the total efficient costs of serving the customers assigned to the tariff, or do not enable us to recover our regulated revenue, we are permitted to apply other tariff components or approaches to meet those requirements. Importantly, however, any additional tariff components or other approaches to setting tariffs must influence customers' behaviour as little as possible relative to the behaviour arising under 'pure' LRMC tariffs.

These new requirements do not apply to this Pricing Proposal due to transitional arrangements.[16] However, we have restructured our tariffs over the last two years to align with the new requirements and have continued to refine our approach to LRMC in 2016–17.

### 4.9.1 Our approach

Appendix C of our TSS explains our LRMC calculation methodology and our approach to incorporating the LRMC in our tariff structures and rates. A useful summary is also provided in Section 5.3 of our TSS.

We have applied the approach detailed in our TSS in 2016–17. However, we have revisited some of the inputs used in our calculations, following the release of the AER's Distribution Determination in October 2015. Specifically, we have:

- applied a real vanilla Weighted Average Cost of Capital of 3.42 per cent, consistent with the Distribution Determination
- replaced our proposed capital expenditure forecasts with the AER's capital expenditure allowances
- adjusted the proportion of Connections expenditure (less capital contributions) from 100 per cent to 50 per cent, in recognition that not all of this expenditure is demand related.

These changes have resulted in LRMC outcomes that are, in all cases, lower than those calculated in 2015–16 (refer to Table 4.5).

### 4.9.2 Application of LRMC in tariff-setting

Ergon Energy's suite of network tariffs includes:

- 'legacy tariffs' or tariff structures that have been in place for many years and which reflect more compromises in respect of the signaling of the LRMC than we consider ideal in the long run
- for all non-site-specific tariff classes, an alternative optional tariff structure(s) that customers can adopt through their choice of retail tariff. These 'LRMC-based tariffs' place a higher and more appropriate weight on signaling the LRMC of using the distribution network.

The application of the LRMC to each of these tariff structures in 2016–17 is summarised below.

#### Cost reflective tariffs

Ergon Energy has applied the LRMC values contained in Table 4.5 to the peak charging component of each customer class in 2016–17.

[16] NER, clause 11.73.1(b).

**Table 4.5: LRMC charges**

| Customer class | Zone | 2015-16 | | 2016-17 | |
|---|---|---|---|---|---|
| | | Calculated | Applied | Calculated | Applied |
| **SAC** | | **$/kW p.a.** | | | |
| SAC Small Residential (STOUE & STOUD) | East | 472.00 | 189.00 | 376.00 | 212.00 |
| | West | 1,180.00 | 472.00 | 939.00 | 531.00 |
| | Mount Isa | 472.00 | 189.00 | 304.00 | 212.00 |
| SAC Small Business (STOUE & STOUD) | East | 472.00 | 189.00 | 376.00 | 212.00 |
| | West | 1,180.00 | 472.00 | 939.00 | 531.00 |
| | Mount Isa | 472.00 | 189.00 | 304.00 | 212.00 |
| SAC Large (STOUD) | East | 472.00 | 189.00 | 300.00 | 212.00 |
| | West | 1,180.00 | 472.00 | 751.00 | 531.00 |
| | Mount Isa | 472.00 | 189.00 | 304.00 | 212.00 |
| **CAC** | | **$/kVA p.a.** | | | |
| 22/11 kV Line (STOUD) | East | 291.00 | 145.50 | 217.00 | 217.00 |
| | West | 722.50 | 722.50 | 543.00 | 543.00 |
| 22/11 kV Bus (STOUD) | East | 200.00 | 100.00 | 132.00 | 110.00 |
| | West | 500.00 | 500.00 | 330.00 | 330.00 |
| Higher Voltage (STOUD) | East | 50.00 | 50.00 | 33.00 | 33.00 |
| | West | 125.00 | 250.00 | 83.00 | 83.00 |

### Legacy tariffs

Efficient application of the LRMC to legacy tariffs is more challenging, given the lack of correlation between the cost of incremental change in demand and the charging parameters within each legacy tariff. Our application of the LRMC to tariff-setting for these tariffs is detailed in Appendix C of our TSS.

## 4.10 Transaction costs

Clause 6.18.5(b)(2)(i) of the NER requires each tariff and, if it consists of two or more charging parameters, each charging parameter for a tariff class to be developed having regard to transaction costs associated with the tariff or charging parameter.

'Transaction costs' in this context refer to the costs to Ergon Energy, retailers and customers of designing/developing and implementing economically efficient tariffs.

In the absence of this requirement, a narrow interpretation of economic efficiency could suggest that every customer at a different connection point should face a unique tariff to reflect the precise LRMC of network services at their location. However, such an approach would impose extremely high development, implementation and on-going transactional costs, and would be unstable. At this time, it is not considered to be economically efficient or beneficial.

For 2016–17, Ergon Energy has altered the structure or format of some of our existing network tariffs. These changes are explained in detail in Section 6.3.3. While Ergon Energy recognises some of these changes will increase transaction costs for both us and retailers in the short-term (e.g. system changes), they have primarily been driven by:

- the need to better align our legacy tariffs with the LRMC pricing principle (e.g. changes being made to the first consumption block of the IBT)
- the need to ensure better cost reflectivity in underlying charges (e.g. changes to application of CAC STOUD demand charges)
- stakeholder feedback on simplifying our demand-based tariffs.

These are necessary trade-offs in developing and implementing our network tariffs.

Finally, we note, for the most part, customers have the option to move to more cost reflective tariffs. Therefore, customers have more choice and control in how they are charged for their use of the network and can make their own informed decisions on which tariff they prefer.

## 4.11 Response to price signals

Clause 6.18.5(b)(2)(ii) of the NER requires each tariff and, if it consists of two or more charging parameters, each charging parameter for a tariff class to be developed having regard to whether customers of the relevant tariff class are able or likely to respond to price signals.

As a result of tariff reform Ergon Energy is transitioning to explicit LRMC-based tariffs. We have a number of legacy tariffs that are offered in parallel with the optional LRMC-based tariffs.

LRMC tariffs introduce new and different pricing principles to the legacy tariffs. Effectively, Ergon Energy's tariffs are in transition from an accounting based interpretation of historic cost-causality to a forward looking LRMC basis incorporating effective economical pricing principles that inform efficient and optimal usage of the network.

LRMC pricing principles result in a two part tariff outcome. The first part promulgates the LRMC price signal while the second part addresses residual revenue recovery. In developing the LRMC-based tariffs, our objective has been to present the LRMC component through parameters which are as cost reflective as possible and aligned with enabling customer responses that support optimal use (or not) of the network.

In establishing and populating the parameters to recover residual revenue, Ergon Energy has targeted minimising any distortionary impact of the non-LRMC-based parameters on customer response to the LRMC signals.

Therefore, Ergon Energy's tariffs have been established with a view to developing LRMC tariff parameters that customers are likely and able to respond to, while choosing and calibrating residual recovery parameters that are less likely to distort the LRMC signals, encourage inefficient use of the network, or encourage inefficient by-pass.

Basically we have calibrated the LRMC-based tariffs to maximise response to the LRMC signal and minimise any possible distortionary response to the other parameters.

In applying these principles in 2016–17, we have not adopted full incorporation of the LRMC in the LRMC parameter for all tariffs. Instead, we are adopting a transitional approach which is expected to see the LRMC parameter progressively become stronger while the residual components are reduced.

Consistent with the above, the LRMC is recovered over a relatively short proportion of the year. The LRMC period for Ergon Energy is calibrated seasonally (December to February), by day of week, and by time of day. Peak times are different between the residential and business customer segments for

SAC Small customers. The LRMC is calibrated in demand (kW for SAC and kVA for CAC) for STOUD tariffs. A STOUE tariff is also offered for SAC Small customers.

The peak demand rates have not only been set with a view to customers being able to respond to the LRMC price signal, but also to ensure that the signal is active only when additional demand on the network is likely to contribute to driving future network augmentation.

The role of the remaining parameters is recovery of residual revenue with as little distortionary impact on network usage as possible. The fixed, capacity, off-peak actual demand and volume (kWh) parameters have been calibrated to support minimal customer demand response.

It is important to note that the extent to which these network signals are actually seen by the majority of customers in our network is dependent on the Queensland Competition Authority's (QCA) determination on regulated retail prices for 2016–17.

The QCA, under delegation from the Queensland Government, sets regulated retail prices based on its latest forecasts of providing electricity services. To calculate each regulated retail tariff (apart from historical transitional tariffs), the QCA uses a 'Network plus Retail' approach. The underlying network cost component may be based on our network tariffs and/or rates, or those of Energex Limited (Energex).

This affects customers' ability to respond to our network price signals.

## 4.12 Designated pricing proposal charges

### 4.12.1 Background

Under the NER, Ergon Energy is able to recover transmission-related costs associated with:

- the use of Powerlink's transmission network to deliver high voltage electricity from generators to our network
- Avoided TUOS charges paid to eligible EGs
- payments made to other DNSPs for the supply of distribution services. For Ergon Energy, this includes our connection to Energex's network at Postman's Ridge.

In addition, Attachment 14 of the Distribution Determination allows us to pass through:

- charges levied on Ergon Energy for use of the 220 kV network which supplies the Cloncurry network in our Mount Isa Zone[17]
- entry and exit services charged by Powerlink at three connection points – Stoney Creek, Kings Creek and Oakey Town.[18]

These costs are recovered from customers through designated pricing proposal charges, or 'TUOS' charges, which form part of our network tariffs.

### 4.12.2 Allocation

#### Allocation of Powerlink charges[19]

Powerlink charges Ergon Energy at the Transmission Connection Point level.

17 Treated as an inter-distributor payment for the purposes of the TUOS unders and overs account.
18 Treated as a designated pricing proposal charge to be paid to a Transmission Network Service Provider (TNSP) for the purposes of the TUOS unders and overs account.
19 Includes the entry and exit services charged by Powerlink for the three connection points described above.

Their charges have four components:

- Entry/Exit Connection Price ($/month)
- Capped Customer TUOS Usage Price: Usage Capacity Price ($/kW/month of nominated demand plus $/kW/month average demand)
- Customer TUOS General Prices: General Energy Charge (c/kWh of historical energy)
- Transmission Customer Common Service Prices: Common Service Energy Price (c/kWh on historical energy).

Our network tariff calculation process allocates these components, on a cost reflective basis, to Ergon Energy's TUOS charging structures. This conversion is shown in our *Information Guide for Standard Control Services Pricing*.

These charges are then apportioned by Ergon Energy to customers and/or customer groups on the following basis:

- customer numbers for the Entry/Exit Connection Price
- forecast any time maximum demand (ATMD) for the Usage Capacity Price
- forecast energy use for the remaining components.

For SAC Small, SAC Large and CACs, Transmission Connection Points are allocated to one of three geographical TUOS Regions. TUOS charges are then calculated based on the combined totals. This has the advantage of simplifying tariffs, while still providing clear TUOS locational signals for these customers.

For those CACs that have a primary and alternate supply[20] (as deemed by Ergon Energy), the following TUOS arrangements apply:

- *Primary supply* – standard rates and conditions for each charge
- *Alternate supply* – standard rates and conditions for each charge, except:
  - no TUOS fixed charge applies
  - the authorised demand for the TUOS capacity charge is set at zero.[21]

This means, with the exception of the TUOS fixed charge, alternate supplies to customers are charged at the standard rates (applicable to the voltage of the connection) for all metered quantities. However, with an authorised demand set at zero for the alternate connection, the capacity charge will only apply to the ATMD in any month when a changeover to the alternate supply takes place.

Ergon Energy intends to review alternate supplies and, if necessary, will consult on this further and seek to include this review in the revised TSS in September 2016.

For ICC connections on site-specific charges, Ergon Energy takes into account the fact that customers can be supplied from different connection points depending on switching arrangements. Charges will continue to be apportioned based on the actual Transmission Connection Points the connection is supplied from. A weighted average methodology is applied for each of the Transmission Connection Points so that these site-specific connections have cost reflective TUOS charges.

TUOS charges for CACs and ICCs are presented in kVA.

[20] Also referred to as back-up supply.
[21] This is also the case for the DUOS capacity charge.

### Network charges from other DNSPs

In the Toowoomba area, Ergon Energy takes supply from Energex at its Postman's Ridge Transmission Connection Point and distributes to a group of customers in the area. This is done on economic grounds. Energex bills Ergon Energy a network service charge for these network services. These charges are forecast each year and are added to the Powerlink charges at our Middle Ridge Transmission Connection Point. This occurs before the allocation process identified above.

In the Mount Isa Zone, Ergon Energy is charged for the use of the unregulated 220 kV network which supplies the Cloncurry township. These costs are passed through to all customers in the Mount Isa Zone via TUOS charges, using an allocation method similar to that applied to Powerlink charges in the other TUOS Regions.

### Avoided TUOS payments

Where Ergon Energy is liable to pay an Avoided TUOS payment to an EG, the payment amount is recovered as part of the TUOS volume charges passed through to customers at the same connection point as the EG.

## 4.12.3 Recovery

Clause 6.18.7(b) of the NER requires that the amount to be passed on to customers for a particular regulatory year must not exceed the estimated amount of the designated pricing proposal charges (TUOS) for the relevant regulatory year adjusted for any over or under recovery.

Further, clause 6.18.7(c) of the NER states that:

> *The over and under recovery amount must be calculated in a way that:*
>
> *(1) subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER in the relevant distribution determination for the Distribution Network Service Provider;*
>
> *(2) ensures a Distribution Network Service Provider is able to recover from retail customers no more and no less than the designated pricing proposal charges it incurs; and*
>
> *(3) adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year.*

Attachment 14 of the Distribution Determination sets out the requirements that Ergon Energy must comply with under clause 6.18.7 of the NER.

Ergon Energy ensures that any difference between revenue recovered from customers from TUOS charges and the actual transmission-related costs paid by Ergon Energy is offset by an annual unders and overs process. Under these arrangements there is a two year lag between the year in which the under or over recovery occurs and the year in which the adjustment to the expected TUOS revenue to be recovered is made.

Table 4.6 below sets out Ergon Energy's 2014–15 under recovery based on information lodged in our 2014–15 Annual Performance Regulatory Information Notice (RIN). As highlighted in our 2015–16 Pricing Proposal, Ergon Energy has identified an issue in relation to the total Avoided TUOS payments included in the 2013–14 regulatory year. Ergon Energy is proposing an adjustment of $1.98 million to the opening balance of the TUOS unders and overs account to correct this misstatement.[22] This is subject to approval by the AER as part of this Pricing Proposal.

[22] This is consistent with the re-audited 2013–14 TUOS figure included in our 2014–15 Annual Performance RIN.

This table satisfies the requirements of Attachment 14 of the Distribution Determination and hence clause 6.18.7 of the NER. Appendix 2 sets out the calculation of the TUOS unders and overs account.

**Table 4.6: Calculation of TUOS unders and overs account ($'000)**

| | 2014-15 Year t-2 (actual) | 2016-17 Year t (forecast) |
|---|---|---|
| **(A) Revenue from designated pricing proposal charges (DPPC)** | $315,488 | $392,424 |
| **(B) Less DPPC related payments for regulatory year =** | $322,525 | $392,424 |
| + DPPC charges to be paid to TNSP | $314,473 | $380,707 |
| + Avoided TUOS payments | $1,912 | $2,360 |
| + Inter–distributor payments | $6,037 | $3,276 |
| + DPPC revenue under/over recovery approved | $104 | $6,081 |
| **(A minus B) Under/over recovery of revenue for regulatory year** | ($7,036) | ($0) |
| **DPPC unders and overs account** | | |
| Nominal WACC t-2 (per cent) | 9.72% | |
| Nominal WACC t-1 (per cent) | 6.01% | |
| Opening balance | $0 | ($6,081) |
| Adjustment to opening balance to correct error in 2015-16 account* | $1,984 | n/a |
| Interest on opening balance for 1 regulatory year | $119 | n/a |
| Under/over recovery of revenue for regulatory year | ($7,036) | $6,081 |
| Interest on under/over recovery for 2 regulatory years | ($1,148) | n/a |
| **Closing balance** | ($6,081) | $0 |

* This adjustment is subject to approval by the AER as part of this Pricing Proposal.

## 4.13 Jurisdictional scheme amounts

### 4.13.1 Background

Jurisdictional schemes are certain programs implemented by state governments that place legislative obligations on DNSPs. Jurisdictional schemes comprise:

- schemes set out explicitly under clause 6.18.7A(e) of the NER. For Queensland, this currently includes the Solar Bonus Scheme, which obligates Ergon Energy to pay a FiT for energy supplied into our distribution network from specific micro-embedded generators[23]

- those schemes determined by the AER to be jurisdictional schemes under clause 6.18.7A(l) of the NER. For Queensland, this currently includes the energy industry levy. Ergon Energy is obligated under our Distribution Authority to pay a proportion of the Queensland Government's funding commitments for the AEMC in relation to this levy.

Our Pricing Proposal must set out how jurisdictional scheme amounts (i.e. the amount(s) we are obligated to pay under the scheme) for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from the over or under recovery of those amounts.[24]

### 4.13.2 Jurisdictional scheme eligibility

Clause 6.18.2(b)(6B) of the NER requires our Pricing Proposal to describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria.

The last jurisdictional scheme approval date for the Solar Bonus Scheme was 21 May 2015 (i.e. the date we submitted our 2015–16 Pricing Proposal to the AER). Since that time, the jurisdictional scheme has not been amended.

We note the Queensland Productivity Commission (QPC) is currently undertaking a review of electricity prices in Queensland. As part of this review, the QPC asked stakeholders to provide advice on a better alternative for funding the Solar Bonus Scheme. A Final Report is due to be submitted to the Queensland Government on 31 May 2016. The outcomes of this review may impact the Solar Bonus Scheme. If this occurs, we will liaise with the AER on an appropriate path forward.

The energy industry levy was approved on 22 April 2016. There have been no changes since this approval date.

### 4.13.3 Allocation

Clause 6.18.7A(a) of the NER requires Ergon Energy's Pricing Proposal to provide for tariffs designed to pass on to customers jurisdictional scheme amounts for approved jurisdictional schemes.

Consistent with our approach in 2015–16, revenue in respect of jurisdictional scheme amounts has been allocated to tariff classes using an allocation process that is similar to how overhead costs incorporated in DUOS charges are allocated.

The total revenue requirement for each tariff class is then converted into tariffs made up of a:

- fixed charge ($/day) and a volume charge ($/kWh) for SACs[25] and CACs
- fixed charge ($/day) for ICCs.

Jurisdictional scheme charges apply to all network tariffs, except unmetered supply and EGs.

### 4.13.4 Recovery

Clause 6.18.7A(b) of the NER requires that the amount to be passed on to customers for a particular regulatory year must not exceed the estimated amount of jurisdictional scheme amounts for a DNSP's approved jurisdictional scheme(s) adjusted for any over or under recovery.

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23 The scheme operates under clause 44A of the *Electricity Act 1994 (Qld).*
24 NER, clause 6.18.2(b)(6A).
25 A fixed charge does not apply to controlled load tariffs.

Further, clause 6.18.7A(c) of the NER states that:

*The over and under recovery amount must be calculated in a way that:*

*(1) subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER for jurisdictional scheme amounts in the relevant distribution determination for the Distribution Network Service Provider, or where no such method has been determined, with the method determined by the AER in the relevant distribution determination in respect of designated pricing proposal charges;*

*(2) ensures a Distribution Network Service Provider is able to recover from customers no more and no less than the jurisdictional scheme amounts it incurs; and*

*(3) adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year.*

Attachment 14 of the Distribution Determination sets out the requirements that Ergon Energy must comply with under clause 6.18.7A of the NER. Specifically, Ergon Energy must provide details of calculations in the format set out in Table 14.3 of the Distribution Determination. This is provided in Table 4.7 below.

Appendix 2 sets out the calculation of the jurisdictional scheme unders and overs account.

It is important to note actual FiT payments incurred by us in 2014–15 will be recovered through our DUOS charges in 2016–17. This adjustment is made in the TAR formula, as a cost pass through amount.

**Table 4.7: Calculation of jurisdictional scheme unders and overs account ($'000)**

| | 2014-15 Year t-2 (Actual) | 2016-17 Year t (Forecast) |
|---|---|---|
| **(A) Revenue from jurisdictional schemes** | $0 | $107,801 |
| **(B) Less jurisdictional scheme payments for regulatory year =** | $0 | $107,801 |
| + Jurisdictional scheme payments (Solar Bonus Scheme) | $0 | $107,640 |
| + Jurisdictional scheme payments (Energy industry levy) | $0 | $161 |
| + Jurisdictional scheme amounts revenue under/over recovery approved | $0 | n/a |
| **(A minus B) Under/over recovery of revenue for regulatory year** | $0 | $0 |
| **Jurisdictional scheme amount unders and overs account** | | |
| Nominal WACC t-2 (per cent) | 9.72% | |
| Nominal WACC t-1 (per cent) | 6.01% | |
| Opening balance | $0 | $0 |
| Interest on opening balance for 1 regulatory year | $0 | n/a |
| Under/over recovery of revenue for regulatory year | $0 | $0 |
| Interest on under/over recovery for 2 regulatory years | $0 | n/a |
| **Closing balance** | $0 | $0 |

## 4.14 Expected price trends

Clause 6.18.9(a)(3) of the NER requires Ergon Energy to provide a statement of expected price trends, to be updated each regulatory year, that gives an indication of how we expect prices to change over the regulatory control period and the reasons for the expected changes.

Based on current projections, we expect the overall revenue we collect for the use of the network will be stable and remain below what we recovered in 2014–15 for the remainder of this regulatory control period (i.e. 2017–18 to 2019–20). This is in line with our best possible price commitment.

Appendix 6 sets out our indicative price trends. The indicative prices detailed in this appendix are based on current expectations regarding annual pricing inputs. The underlying assumptions we have applied for each type of charge are set out in Table 4.8.

Individual customer outcomes may differ significantly from the price trends indicated. This is particularly the case for major customers where changes in connection arrangements (e.g. authorised demand) can be a significant driver of future trends.

Other charges that do not relate to the costs of using our network (i.e. TUOS and jurisdictional schemes) may also affect future price trends.

**Table 4.8: Assumptions underpinning the expected price trends**

| Type of charge | Assumptions applied |
|---|---|
| DUOS | • Applied the revenues from the Distribution Determination, with no adjustments for the s-factor,[26] inflation or the return on debt. In practice, the AER is likely to approve adjustments for these factors, in accordance with the revenue cap formula.<br>• Included a forecast DUOS over recovery adjustment in 2017–18, noting the final position is not yet known. No adjustments have been applied in future years.<br>• Used high level assumptions regarding:<br>○ energy and demand<br>○ customer numbers<br>○ customer churn.<br>These forecasts will be updated each year, once actual outcomes from prior years are known. |
| TUOS | • Forecast expense amounts for Powerlink charges were based on discussions with Powerlink, taking into account their revenue proposal for the 2017–18 to 2021–22 period.<br>• For Avoided TUOS and inter-distributor payments, used the previous year's forecast expense and adjusted it by a forecast inflation rate of 2.50 per cent.[27]<br>• Included a forecast TUOS under recovery adjustment in 2017–18, noting the final position is not yet known. No adjustments have been applied in future years. |
| Jurisdictional scheme | • Used high level assumptions regarding the total number of FiT payments we expect to make for the relevant year. These forecasts take into account:<br>○ the number of connected inverter energy systems expected to be eligible for the Solar Bonus Scheme (44 cent) in the relevant year<br>○ the mean size of the installed solar arrays<br>○ historical monthly export in kWh per unit of installed capacity.<br>In producing these forecasts, we assumed:<br>○ There are no major policy or technology shifts affecting customers receiving the 44 cent FiT.<br>○ The current trends of factors affecting the 44 cent FiT will continue into the future.<br>• Forecast energy industry levy amounts were based on information provided by the Department of Energy and Water Supply.<br>• Included a forecast jurisdictional scheme under recovery adjustment in 2017–18, noting the final position is not yet known. No adjustments have been applied in future years. |

[26] Except 2017–18. We have applied an estimated s-factor.
[27] For Chumvale, we apply 50 per cent of the applicable CPI increase.

# 5 Alternative Control Services

## 5.1 Tariff classes

Ergon Energy's tariff classes for Alternative Control Services are differentiated at the highest level according to the AER's classification of services and the basis of pricing approved by the AER:

- fee based services
- quoted services
- Default Metering Services
- Public Lighting Services.

Fee based services are further separated into two tariff classes based on the type of feeder to which a customer requesting the service is connected.

The consequent tariff classes under this approach are set out in Table 5.1 below, thus meeting the requirements of clause 6.18.2(b)(1) and clause 6.18.3(a) of the NER.

**Table 5.1: Ergon Energy's Alternative Control Service tariff classes**

| Tariff class |
|---|
| Fee based services (urban/short rural) |
| Fee based services (long rural/isolated) |
| Quoted services |
| Default Metering Services |
| Public Lighting Services |

As indicated in Section 4.1 above, all of Ergon Energy's customers for Direct Control Services are a member of one or more tariff classes (thus meeting clause 6.18.3(b) of the NER). This is because Alternative Control Services are a subset of Direct Control Services and all of Ergon Energy's customers are assigned to at least one network tariff and one Standard Control Service tariff class. Further, clause 6.18.3(c) of the NER is met by Ergon Energy distinguishing between the tariff classes for Standard Control Services and for Alternative Control Services.

Finally, clause 6.18.3(d) of the NER requires that a tariff class be constituted with regard to the need to group customers together on an economically efficient basis, and the need to avoid unnecessary transaction costs. As noted above, this clause requires a balance to be struck between setting tariffs that send efficient signals to individual customers while minimising the costs of developing and implementing a large number of bespoke tariffs.

Ergon Energy's tariffs for Alternative Control Services are grouped according to the classification and basis of pricing determined by the AER in its Distribution Determination. This aids in providing tariffs that appropriately reflect the costs incurred in providing the relevant service to the relevant type of customer. At the same time, the tariffs within each tariff class have been grouped together in a manner that is easy for customers and retailers to understand, which avoids unnecessary transaction costs as a result of tariff proliferation.

## 5.2 Assigning and reassigning customers to tariff classes

Attachment 14 of the Distribution Determination outlines the general procedures Ergon Energy must comply with when assigning or reassigning customers to tariff classes. Consistent with these procedures, Ergon Energy has developed a more detailed document for tariff class (and tariff) assignments and reassignments for Alternative Control Services (refer to Appendix I of our TSS). Ergon Energy will comply with these procedures in 2016–17.

As highlighted in Section 4.2 above, we must outline in this Pricing Proposal how we will review and assess the basis on which a customer is charged in certain circumstances. However, as the basis of charge and prices for Alternative Control Services is capped and/or developed using an approved formula, Ergon Energy considers the charging parameters of our Alternative Control Service tariffs do not vary according to the usage or load profile of a customer (as it does for Standard Control Services). Therefore, Ergon Energy considers that this requirement does not apply to our Alternative Control Services. Consequently, Ergon Energy does not need to assess or review the basis (the approved formulae and price caps) on which a customer is charged for Alternative Control Services.

## 5.3 Cost input changes for fee based and quoted services

In Appendix G of our TSS, we highlight that annual changes to cost inputs used in calculating prices for our fee based services and quoted services will be submitted to the AER for approval in our Pricing Proposal. Accordingly, the following sections set out the nature of these changes, with quantitative information available in Appendix 5.

It is important to note that these adjustments impact the calculation of our fee based and quoted services prices in different ways. This is illustrated in Table 5.2.

**Table 5.2: Impact of cost input changes on fee based and quoted services prices**

| Cost input | Impact on fee based services | | Impact on quoted services | |
|---|---|---|---|---|
| | Capped price [a] | Cost build-up | Illustrative | Actual |
| Labour escalator | ✗ | ✓ | ✓ | ✓ |
| Fleet escalator | ✗ | ✓ | ✓ | ✓ |
| Materials escalator | ✗ | ✓ | ✓ | ✗ [b] |
| Contractor services escalator | ✗ | ✗ [c] | ✓ | ✗ [b] |
| Labour on cost | ✗ | ✓ | ✓ | ✓ |
| Materials on cost | ✗ | ✓ | ✓ | ✓ |
| Overhead rates | ✗ | ✓ | ✓ | ✓ |

**Notes:**

a. The capped price for each fee based service is not dependent on changes to the underlying cost inputs. Rather, the capped price is calculated in accordance with the price cap formula.

b. Ergon Energy will charge the actual costs incurred for Contractor Services and Materials, depending on the requirements of the job requested.

c. There are no Contractor Services used in the provision of fee based services.

### 5.3.1 Escalators

Ergon Energy has adjusted the nominal labour, fleet, materials and contractor services escalators by annual CPI data to December quarter 2015 as published by the ABS.

### 5.3.2 Labour on costs

Ergon Energy has applied the labour on cost rate used in 2015–16 for ordinary time hours (43.5 per cent). The labour on cost rate for overtime hours has reduced to 6 per cent (from 8 per cent in 2015–16).

### 5.3.3 Materials on costs

In 2016–17, the materials (stores) on cost rate will increase to 16.6 per cent (from 12 per cent in 2015–16). This rate has been calculated based on our latest forecasts of Logistic Support costs to be recovered in 2016–17 and the proportion of Stores Issues across each Line of Business (LOB) (based on historical analysis of Stores Issues over the 2012–13 to 2015–16 period).

### 5.3.4 Overhead rates

Ergon Energy has recalculated the overhead rates.[28] Consistent with our AER-approved Cost Allocation Method (CAM),[29] Ergon Energy uses the following methodology to calculate the overhead rates for our fee based services (cost build-up only) and quoted services:

1. **Determine total shared costs (overheads) for the regulatory year**. Budget data is used to set costs expected to relate to shared 'support' services which cannot be directly attributable to a particular activity or work plan. For example, shared costs include costs associated with business units that provide corporate support services across the Ergon Energy Group (Corporate Overheads). Shared costs also include costs associated with support services provided within Ergon Energy's operational business units that have not been directly attributed (Operational Overheads). Operational Overheads predominantly represent labour and administration costs associated with (but not limited to) senior management, technical and operations support, including maintenance and construction standards, mapping, technical data records and field investigations and auditing.
2. **Allocation of total shared costs (overheads) between Ergon Energy Group districts and Ergon Energy Corporation Limited LOB**. Ergon Energy Corporation Limited, as the parent entity of the Ergon Energy Group, provides 'support' services to a number of other districts (or legal entities) and LOB within Ergon Energy Corporation Limited. These include:
    - *Ergon Energy Queensland Pty Ltd (EEQ)* – a subsidiary entity responsible for providing non-competing electricity retail services to non-market customers
    - *Ergon Energy Telecommunications Pty Ltd* – a subsidiary entity and licensed telecommunications carrier providing wholesale high-speed data capacity to the Ergon Energy Group and external customers
    - *SPARQ Solutions Pty Ltd (SPARQ)* – a joint venture company formed by Ergon Energy and Energex providing information technology and telecommunications to Ergon Energy and Energex. Ergon Energy holds a 50 per cent share in SPARQ
    - *Ergon Energy Corporation Limited LOBs* – the parent entity is broken down over various LOB – Regulated, Non-Regulated, Isolated System, External, Powerlink and Workshop Services.

    Once the districts and total shared costs for the regulatory year are determined, the costs are then allocated to each entity in the Ergon Energy Group using causal allocators in accordance with the CAM and in some instances using a commercial agreement between Ergon Energy

[28] Ergon Energy has not updated the overhead rate applying to the administration labour rate. Consistent with the Distribution Determination, we have applied the AER's maximum overhead rate.

[29] As approved on 15 August 2014. Available at http://www.aer.gov.au/node/27108.

and SPARQ. The choice of allocator depends on the type of service provided. For example, where the shared costs are identified as relating solely to a legal entity within the Ergon Energy Group, costs are directly allocated to that entity. In other cases, the number of transactions undertaken or time spent in providing the service may be the driver to calculate the allocation of work and shared costs to each entity.

3. **Determine the direct costs for the regulated LOB.** Budget data is used to set costs expected to be directly attributable to regulated operating expenditure (opex) and capital expenditure (capex) required for delivering our work plans. These costs are determined using an Activity Based Costing Method which maps and directly attributes expected costs of particular activities to the Chart of Accounts.

4. **Allocation of shared (support) costs between regulated opex and capex activities**. For the pool of shared (support) costs that have been allocated to the regulated distribution services provided by Ergon Energy Corporation Limited, the next step is to allocate these shared (support) costs between regulated opex activities and regulated capex activities.

   Where the shared (support) cost is directly attributable to either regulated opex or regulated capex, the cost is charged directly to that activity.

   For shared (support) costs that are shared between operating and capital activities, the costs are allocated on the basis of the proportional values of the operating and capital work plans (i.e. direct costs).

   The outcome is a pool of shared (support) costs related to regulated opex activities and a pool of shared costs related to regulated capex activities.

5. **Calculate the overhead rate**. The shared (support) cost pools determined in Step 1 above are then converted to shared cost percentage rates for regulated opex activities and regulated capex activities as follows:

$$\text{Customer service Opex overhead rate \%} = \frac{\text{Shared cost for customer service opex activities}}{\text{Work plan costs for customer service opex activities}}$$

$$\text{General regulated Opex overhead rate \%} = \frac{\text{Shared cost for general regulated opex activities}}{\text{Work plan costs for general regulated opex activities}}$$

$$\text{General regulated Capex overhead rate \%} = \frac{\text{Shared cost for regulated capex activities}}{\text{Work plan costs for regulated capex activities}}$$

6. **Select appropriate overhead rate**. The overhead rate used by Ergon Energy for our fee based services and quoted services is the calculated overhead rate as explained above.

   For example, the regulated capex overhead rate applies to customer services capital work and the customer services opex overhead rate applies to customer services operational work. An exception to using the customer services opex rate is when opex costs are capitalised. In these instances the regulated capex overhead rate will apply. For example, if Ergon Energy substantially relocates assets at the request of a customer which changes our network, then we expect to treat this as capex and we would apply the regulated capex overhead rate.

Ergon Energy's 2016–17 overhead rate calculation is provided in Appendix 5.

## 5.4 Tariff schedules

Clause 6.18.2(b)(2) of the NER requires Ergon Energy to set out the proposed tariffs for each tariff class. Accordingly, the 2016–17 tariffs for Alternative Control Services are set out in Appendix 4.

## 5.5 Avoidable and stand alone costs

As noted in Section 4.8, clause 6.18.5(a) of the NER requires that for each tariff class, the revenue expected to be recovered should lie on or between an upper bound representing the stand alone cost of serving the customers who belong to that class and a lower bound representing the avoidable cost of not serving those customers.

Our approach to determining avoidable and stand alone costs for our Alternative Control Services is set out in Section 10.2 of our TSS. Consistent with this approach, we have not undertaken any quantitative analysis of our stand alone and avoidable costs for Alternative Control Services.

## 5.6 Long Run Marginal Cost, transaction costs and response to price signals

The NER requires each tariff and, if it consists of two or more charging parameters, each charging parameter of a tariff class:

- to take into account the LRMC for the service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates (clause 6.18.5(b)(1))
- to be developed having regard to transaction costs associated with the tariff or charging parameter (clause 6.18.5(b)(2)(i))
- to be developed having regard to whether customers of the relevant tariff class are able or likely to respond to price signals (clause 6.18.5(b)(2)(ii)).

Ergon Energy's tariffs for Alternative Control Services comprise one charging parameter. Therefore, consistent with clause 6.18.5 of the NER, Ergon Energy is only required to demonstrate compliance for each tariff, not the individual charging parameters.

### 5.6.1 Long run marginal cost

Each tariff and the movement in tariffs between regulatory years are determined by the AER through the application of caps on the prices of individual Alternative Control Services. The AER therefore determines the LRMC of each tariff when it establishes the initial prices and sets the inputs, such as the X factors, to be used in the price cap formulae. In establishing these controls, the AER has regard to both the National Electricity Objective and Revenue and Pricing Principles.

Further information on how our ACS tariffs take into account the LRMC is provided in Section 10.3 of our TSS.

### 5.6.2 Transaction costs

Ergon Energy notes that our tariff structures for Alternative Control Services have not changed significantly from the structures that were in place in 2015–16. Ongoing stability of the structures results in low transaction costs for customers and retailers.

### 5.6.3 Price signals

Under the formula based approach, customers are sent signals about the true cost of the service that they are able to request. This helps ensure that customers will only use a service if they believe they will gain a larger benefit from the service than it costs Ergon Energy to provide that service in the long term. This helps ensure that Alternative Control Services are provided to customers up to the point where the marginal benefits from using the service equals the marginal costs that use of the service imposes on Ergon Energy. This is consistent with economic efficiency.

In the case of quoted services, customers will have incentives to consider whether a different variant of the service may be preferable (e.g. customers can minimise the cost incurred for some services by choosing to have the service delivered during business hours, if applicable). This, too, is consistent with economic efficiency principles.

By their nature, most Alternative Control Services are services requested by customers that vary according to the specific characteristics or circumstances of the customer. This suggests that customers have the ability and incentive to respond to cost reflective tariffs for these services.

## 5.7 Expected price trends

Clause 6.18.9(a)(3) of the NER requires Ergon Energy to provide a statement of expected price trends, to be updated each regulatory year, that gives an indication of how we expect prices to change over the regulatory control period and the reasons for the expected changes.

Appendix 6 sets out indicative prices for our Alternative Control Services.

Prices for fee based services (capped price), Default Metering Services and Public Lighting Services will be escalated in accordance with the price cap formulae approved by the AER in the Distribution Determination. This annual escalation process typically involves applying:

- the X factor specified in the Distribution Determination (incorporated in the indicative prices)
- a CPI adjustment (to be updated each year).

For quoted services, prices will vary depending on the actual requirements of the service being requested. Prices are expected to change as a result of the following adjustments:

- the difference between forecast and actual inflation
- changes to underlying real costs (refer to Section 5.3 above).

# 6 Other compliance obligations

## 6.1 Tariff adjustment to address revenue shortfalls

Clause 6.18.5(c) of the NER provides that if, as a result of the operation of clause 6.18.5(b), Ergon Energy may not recover the expected revenue, tariffs will be adjusted in accordance with clause 6.18.5(c) of the NER, so as to ensure recovery of expected revenue with minimum distortion to efficient patterns of consumption.

As noted in Sections 4.9 and 4.11, Ergon Energy's charging parameters aim to effectively signal the LRMC to customers, while recovering the remainder of regulated revenues in ways that seek to avoid distorting network usage decisions away from those based on LRMC signals. This means, to the extent that LRMC-based charges are not expected to fully recover Ergon Energy's total regulated revenues, the residual revenue needs to be recovered in some other way. As noted above, Ergon Energy has used fixed, capacity, off-peak actual demand and volume parameters to do this. Residual recovery within each customer group has been based on selecting combinations that minimise distortion of the LRMC signal.

Ergon Energy is planning to modify tariff parameters over time to improve the cost reflectivity and non-distortionary properties of our tariff structures. This is likely to mean capacity and demand charges will more fully reflect LRMC and volume charges will fall (in relative terms) while fixed charges will rise.

## 6.2 Adjustments to tariffs within a regulatory year

Clause 6.18.2(b)(5) of the NER requires that a Pricing Proposal must set out the nature of any variation or adjustment to the tariff that could occur during the course of the regulatory year and the basis on which it could occur.

Variations or adjustments to tariffs will occur where an ICC, CAC or EG advises Ergon Energy that they intend to alter their demand or connection characteristics during 2016–17. In this case, Ergon Energy will recalculate the charging parameters of the tariff (noting that the published rates will continue to apply to CACs). New tariffs will be created for each ICC and EG that connects during 2016–17, in line with the methodology set out in this Pricing Proposal.

During 2016–17, Ergon Energy may also be required to calculate additional tariffs and/or prices for existing services which we have not provided prices for in this Pricing Proposal. This may occur because of a new customer connection or a price has not been established for a service legitimately included in the Distribution Determination. For example, we may develop standardised rates for a customer who is seeking to connect to the Mount Isa network as a CAC.

Ergon Energy will seek approval from the AER to include a tariff and/or price at that time.

In circumstances where Ergon Energy makes changes to methodologies during a regulatory year, Ergon Energy will not recalculate the charging parameters of a tariff to give effect to the change. The tariff that has been calculated to apply to customers in accordance with the methodologies in this Pricing Proposal will continue to be applied, unless Ergon Energy obtains approval from the AER to adjust the tariffs during the course of the regulatory year to reflect the new methodologies.

There are no other variations or adjustments proposed to be made to remaining tariffs during the course of the regulatory year.[30]

## 6.3 Changes between regulatory years

Clause 6.18.2(b)(8) of the NER requires that a Pricing Proposal must describe the nature and extent of change from the previous regulatory year and demonstrate that the changes comply with the NER and any applicable Distribution Determination.

This Pricing Proposal contains several changes since 2015–16. These changes are also largely reflected in our TSS. To the extent we propose changes that are different to what is in the TSS, we will seek to include them in the revised TSS in September 2016.

### 6.3.1 Distribution Determination

The Distribution Determination released in October 2015[31] contained a number of changes that impact pricing arrangements in 2016–17. The main changes since 2015–16 relate to:

- the classification of services
- call out fees for final meter reads
- upfront capital charges for Type 5 and 6 meters.

These changes are described in more detail in the remainder of this section.

A number of other minor changes were also made to the:

- control mechanism formulae for Standard Control Services and Alternative Control Services, and the side constraints formula for Standard Control Services. Ergon Energy has applied these changes in our models and in this Pricing Proposal
- format of the DUOS, TUOS and jurisdictional scheme unders and overs accounts. The AER amended the presentation of the DUOS unders and overs account to reflect the revised Standard Control Services formula and made other changes to the accounts to improve transparency and consistency with other jurisdictions. The AER also corrected the erroneous omission of Avoided TUOS charges from the TUOS unders and overs account. Ergon Energy has applied these changes in Sections 4.5.2, 4.12.3 and 4.13.4.

#### Classification of services

Attachment 13 of the Distribution Determination sets out the classification of distribution services for Ergon Energy in the regulatory control period 2015–20. In its final decision, the AER determined the costs of wasted truck visits that are incurred in providing Standard Control Services should not be recovered through a separate Alternative Control Service charge. Rather, these costs should be recovered via network tariffs.

This means the four ‘Prevented Access’ charges presented in our revised Regulatory Proposal can only apply in instances where there is a wasted attendance associated with an Alternative Control Service.

Ergon Energy notes that we have call out fees for our Alternative Control Services. These call out fees are designed to recover the costs of wasted attendance due to customer/retailer fault. Consequently, to avoid confusion, we have removed the four ‘Prevented Access’ charges in 2016–17.

[30] The exception being the maximum price caps under Schedule 8 of the *Electricity Regulation 2006,* discussed in Section 2.1.3 of this Pricing Proposal.

[31] Prices for 2016–17 are based on this Distribution Determination, whereas the AER’s preliminary decision was used to set prices for 2015–16.

### Call out fees for final meter reads

In 2016–17, Ergon Energy will charge for the costs of wasted attendance related to final meter reads. There are two call out fees, differentiated by feeder type. This is consistent with Attachment 16 of the Distribution Determination.

### Upfront metering charges

In its Preliminary Determination (April 2015), the AER approved three upfront metering charges for the installation of new or upgraded Type 5 or 6 meters from 1 July 2015. We applied these charges in 2015–16.[32]

In our revised Regulatory Proposal (July 2015), we proposed a number of changes to allow us to:

- differentiate upfront metering charges based on the feeder type
- charge for the installation or upgrade of a site with a current transformer (CT) meter.

The AER accepted these changes in its final decision. Accordingly, in 2016–17, we have replaced the three existing upfront capital charges with the following:

- eight new fee based services relating to the installation and provision of Type 5 and 6 meters on or after 1 July 2015 (during business hours), where the new or upgraded meter is required as a result of a customer request. These services are differentiated by the type of meter (i.e. single phase, dual element, polyphase and CT) and the type of feeder the customer is connected to (i.e. either urban/short rural or long rural). Call out fees for these services have also been developed.[33]
- one new quoted service relating to the installation and provision of Type 5 and 6 meters on or after 1 July 2015 (after hours), where the new or upgraded meter is required as a result of a customer request. Call out fees for this service will be calculated in accordance with the quoted services formula.

## 6.3.2 Alternative Control Services

In addition to the changes outlined above, we have made a number of amendments to our Alternative Control Services since 2015–16. These changes are detailed in Table 6.1 below.

[32] Due to system limitations, we also developed 12 additional upfront metering charges associated with the installation of new meters on or after 1 July 2015. Under this two year transition solution, new installations in 2015–16 generally incurred an upfront metering charge, plus a daily capital charge for a period of two years from the date of installation. To achieve a cost neutral outcome for the customer, the relevant AER-approved upfront metering charge was discounted by the Net Present Value of two years' worth of the relevant capital charge(s).

[33] A transition solution will also be required in 2016–17 due to system limitations. We have developed 17 additional upfront metering charges and four call out fees associated with the installation of new meters. Under this transition solution, new installations will generally incur an upfront metering charge, plus a daily capital charge for a period of one year from the date of installation. The relevant AER-approved upfront metering charge will be discounted by one year's worth of the relevant capital charge(s).

**Table 6.1: Summary of changes to Alternative Control Services since 2015–16**

| Service | Changes |
|---|---|
| *Quoted services* | |
| Detailed enquiry response fee | • Expanded to include any embedded generation connection applicant that submits an enquiry under the connection process set out in Chapter 5 of the NER. This is consistent with the *Connecting embedded generators under Chapter 5A* rule change, which allows non-registered embedded generators to elect to proceed under Chapter 5 of the NER and seek a detailed response. |
| Carrying out planning studies and analysis relating to connection applications | • Amended to include real estate developers. |
| Provision of site-specific connection information and advice | • Removed reference to small or major customer connections, to clarify that this service includes real estate development connections. |
| Customer requested appointments | • Expanded this service to explicitly include retailers. We note that retailers are a customer of Ergon Energy (as a distributor) and this change clarifies this.<br>We have amended the service description to highlight that these services are for works initiated by a customer or retailer 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. This is consistent with the wording in the Distribution Determination (albeit with 'retailers' explicitly referenced).<br>Ergon Energy has also included an illustrative example of a retailer requested appointment – 'checking pump size for tariff eligibility'. We currently receive requests from EEQ to perform this service at a customer's premises to confirm tariff eligibility for Tariff 66 (a regulated retail tariff).<br>• We will seek to revise our TSS to reflect this change. |
| Install additional metering | • Removed. This service is no longer required as we have introduced separate fees for new or replacement meters and the service description of our 'Change tariff' service has been amended so that it includes reprogramming for adding or removing tariffs. |
| Special Meter Read | • Clarified that this service does not include final meter reads. The costs of final meter reads are included in the operating expenditure building block of the annual metering charges. |
| Change tariff | • Amended to include reprogramming for adding or removing tariffs. |
| Provision of services for approved unmetered supplies | • Included a potential price for this service, which reflects the costs to attend a premises to verify a load change requested by a customer for an unmetered supply device. The service description has also been amended.<br>• We will seek to revise our TSS to reflect this change. |
| *Default Metering Services* | |
| Annual metering charges – solar | • Expanded the solar capital and non-capital metering charges to include other forms of embedded generation. Ergon Energy is starting to see an increase in alternative technologies, such as battery only micro-embedded generating units, which require the installation of a new meter the same as solar photovoltaic (PV) systems. We consider that there should not be a different treatment because of the technology source requiring the meter.<br>• We will seek to revise our TSS to reflect this change. |

### 6.3.3 Network tariffs

As noted in Section 2.1.2, Ergon Energy is proposing a number of changes to our network tariff structures from 1 July 2016 for our Standard Control Services. These changes are described in more detail in the remainder of this section and have been reflected in Appendix 1 and Appendix 2 (where relevant).

#### Changes to ICC tariffs

##### *EGs with ICC load side*

New rules will apply for EGs who are also classified as an ICC (or CAC) for their load connection. We have observed that, when charging for the ICC load, the kVA and kVAr component may contain a contribution from the generator. This has the potential to increase the total kVA and excess kVAr billing quantities. It is not the intent of load side kVA charging for demand and excess kVAr to include this generator impact. Therefore, in 2016–17, for the purposes of network billing for loads, we will set export kVAr to zero in any interval when kW are imported into our distribution network.

#### Changes to CAC tariffs

##### *Deferral of planned introduction of excess kVAr charges*

As a result of the extensive consultation undertaken over the last two years, customers, retailers and other stakeholders have anticipated the introduction of an excess kVAr charge for CACs in 2016–17. On 17 May 2016, the AER advised that it will not approve this charge until its review of Ergon Energy's Tariff Structure Statement has been finalised. Consequently, we have amended our 2016–17 Pricing Proposal to defer the introduction of the excess kVAr charge for CACs until 1 July 2017.

The proposed introduction of an excess kVAr charge for CACs was to reinforce the price signal introduced by the kVA tariff in 2015–16 and encourage customers to improve their sites' power factor and reduce the network capacity they require.

The ratio of real power (kW) to actual power (kVA) is known as the power factor. A customer's power factor and demand as measured in kVA is important because distribution systems must be designed to supply the actual power required. A low power factor suggests the quantity of actual power delivered to a customer may be able to be reduced. It is more often the case that the cost for the customer to take action to improve power factor is less than the cost of the additional network capacity required if no action is taken. Making the cost to Ergon Energy explicit to the customer allows the customer to make a commercial investment in efficient power factor improvement.

When introduced for CACs, the excess kVAr charge will be calculated monthly based on the power factor recorded at the time of each customer's individual monthly kVA peak. To the extent the actual kVAr during this peak exceeds the customer's permissible kVAr quantity (determined by the customer's authorised demand and the customer's compliant power factor), excess kVAr charges are applied.

To reflect the deferral of the excess kVAr charge for CACs until 2017–18 we have set the excess kVAr per month rate to $0.000 in Appendix 1 of this Pricing Proposal. For the expected price trends contained in Appendix 6, the forecast rate post 1 July 2017 remains at $4.000 per excess kVAr per month.

### *CAC STOUD tariffs*

The following changes have been made to the CAC STOUD tariffs:

- The peak demand charge is now based on the customer's monthly maximum kVA demand during the peak period in each summer month. Previously, this charge was based on the greater of the authorised demand and monthly maximum demand during the peak period.
- The capacity charge is now based on the greater of the customer's authorised demand and the actual monthly half hour maximum demand. It will apply for all 12 months of the year. Over the summer months, it excludes demand occurring during the peak demand window of 10.00 am to 8.00 pm on summer weekdays. In 2015–16, this charge was calculated on the greater of a monthly floor and the monthly maximum demand during the non-summer months.

This structure will improve incentives for CACs to respond to the LRMC signal.

### *EGs with CAC load side*

The changes highlighted above, in relation to EGs with an ICC load side, also apply to CACs.

## Changes to SAC Large tariffs

### *Strengthening the cost reflectivity of the STOUD tariffs*

We are progressively increasing the proportion of LRMC incorporated in the peak demand charge. This will strengthen the cost reflectivity of the STOUD tariffs.

## Changes to SAC Small tariffs

### *Improving the cost reflectivity of the IBT*

The rate for the first 1,000 kWh of annual consumption for the IBT (Residential and Business) has been changed to a positive rate, to progressively align this network tariff with the LRMC pricing principle.

The increase in the rate for the first IBT consumption block will avoid, in the first instance, the option to increase the fixed charge. This will result in a lower customer impact for low consumption customers (<1,000 kWh p.a.) than recovery of the equivalent revenue in the fixed charge.

### *Consolidating the energy charges for the STOUE tariffs*

In 2016–17, the shoulder and peak energy charges (including times) for the STOUE tariffs (Residential and Business) will be consolidated into one peak energy charge. This simplifies the tariffs for retailers and customers, and is a natural progression from our 2015–16 STOUE tariffs, where the shoulder and peak rates were the same. It also allows the LRMC charge (which has been revised higher to reflect the LRMC pricing principle) to be applied over a longer period, reducing the LRMC rate to be applied, without diluting the signal.

The new STOUE structure consolidates the previous peak and shoulder periods into a single peak period. Part of the reason behind introducing the STOUE was its ability to introduce TOU pricing without the need for a smart meter. The STOUE is supported by interval meters which are pre-set and programmed to measure data for the original STOUE structure, which included off-peak, shoulder and peak energy times and rates. Complementary network tariff programs are also established to support the data streams generated by these intervals. Effectively, currently both the meters and the billing system are hard-wired to support the original three part structure. Additionally, retailers may have developed retail tariffs which are dependent on the data streams currently provided by these meters.

The existing metering and billing system can support the peak/shoulder consolidation by applying the peak rate to each of the registers which jointly meter the new extended peak time. To avoid the high cost of change and potential disruption to retail arrangements, we will continue to use the existing billing and metering infrastructure. This will mean that the recovery of the peak charge will be displayed as both peak and shoulder consumption in network tariff bills to retailers.

### *Simplifying and strengthening the cost reflectivity of the STOUD tariffs*

In response to feedback on simplifying the STOUD tariffs (Residential and Business), we have amended the calculation of the peak and off-peak demand charges. The monthly demand charges, for both summer and non-summer, are based on the average demand the customer places on the network in the relevant daily demand window. Previously, the off-peak demand charge was based on the single half-hour maximum demand recorded for the month.

Further, we will look at the highest four demand days in the month, determined by the average demand recorded in the relevant daily demand window. The monthly demand rate will then be applied to the average of these top four demand days. In 2015–16, the peak demand charge in the summer months was calculated by identifying the four days in the month with the highest single half-hour peak period demand and averaging the half-hourly demand during the peak periods on those days.

This more moderated application of the peak charging mechanism minimises the bill impact of any abnormally high peak demand days. Customers have more control over how they use their energy without being substantially impacted by an 'outlier' demand event. It also improves the likelihood of the period measured coinciding with the network-wide peak (peak demand drives our costs, so any opportunity to reduce this demand will benefit all customers).

We are also progressively increasing the proportion of LRMC incorporated in the peak demand charge. This will strengthen the cost reflectivity of the STOUD tariffs.

### Customer impacts

Understanding and managing customer impacts has been a priority in our reform agenda.

The pace we have set for our journey has been all about balancing the short-term, year-on-year impact on individual customers and the longer term community cost if the reforms are not implemented. Modelling commissioned as part of our tariff development work has shown that, if we do not act, customers could be paying an additional $1 billion over the coming decade to use our network.[34] This is a direct result of the cross subsidies that are being created by our legacy tariffs through the take up of technology choices that do not contribute significantly to reducing our cost to serve via the network.

Legacy pricing structures create the wrong customer response, and this distorted customer response means that some customers pay more than what they should be for using the network while other customers are paying less.

Our preferred future is one that provides the right signals to customers so that the choices each customer makes in using the network is reflected in the price they pay (and not in the price other customers pay).

For the longer term, our analysis of the different tariff structures has allowed us to target options that best minimise the overall community cost of energy delivered.

[34] Energeia (2015), *Maximum Demand Tariff Analysis Report*, April 2015.

We note the revenue movements between 2015–16 and 2016–17 are around 2 per cent; primarily driven by an increase in Powerlink charges. Price impacts for SAC Small tariff classes are expected to be higher because of changes in our approach to forecasting the customer count for the fixed charge component of the IBT and controlled load tariffs (see Section 6.4).

For some tariff classes, we expect that some customers will seek to take advantage of cost reflective prices. Legacy tariff structures have been adjusted to reflect the revenue shortfall associated with this forecast customer churn. We believe this is appropriate as customers moving onto cost reflective tariffs will be subject to LRMC-based price signals in their daily utilisation of the network. It is expected that this forecast customer churn will place upward pressure on volume-based tariffs, as more customers move to the optional, demand-based tariffs.

It is important to note that tariff structure changes presented in this Pricing Proposal do not change the revenue we are allowed to collect overall – the reforms are revenue neutral. That is, at least in the short-term, Ergon Energy's total revenue from customer bills neither increases nor decreases as a result of tariff structure changes. Changes within a fixed revenue constraint inevitably result in winners and losers – some customers benefitting from the changes and others being disadvantaged.

In developing the above changes and the resulting tariffs presented in this Pricing Proposal, Ergon Energy has also undertaken an extensive customer and stakeholder consultation process to ensure we understand and consider any customer or broader stakeholder implications. This included:

- publishing a consultation paper in June 2015 and a guide on understanding kVA and kVAr charges for major customers
- hosting several stakeholder sessions, including webinars
- direct engagement with major customers
- other engagement with retailers and government representatives.

Appendix A of our TSS sets out a summary of stakeholder feedback received[35] and our response. Our customer and stakeholder consultation process is ongoing.

### 6.3.4 Jurisdictional scheme charges

#### Energy industry levy

On 22 March 2016, Ergon Energy's Distribution Authority was amended by the regulator to enable the Queensland Government to recover a proportion of the state's funding commitments in respect of the AEMC through an energy industry levy. On 22 April 2016, the AER approved the energy industry levy as a jurisdictional scheme. Therefore, in 2016–17, the jurisdictional scheme amount to be recovered will include both the Solar Bonus Scheme and the energy industry levy.

#### Application to controlled load tariffs

In 2015–16, customers with controlled load tariffs were not subject to jurisdictional scheme charges on their controlled load (secondary) tariff. This approach provided an advantage to customers with controlled load tariffs (where consumption was split over a primary and secondary tariff) compared to those customers on a single supply tariff (where all of the consumption was on the primary tariff).

In terms of efficient recovery of jurisdictional scheme revenue, whether the energy is consumed on a primary tariff or a secondary tariff should not make a difference. It should be applied to the total energy consumption at the premises.

35 As at November 2015.

Therefore, in 2016–17, jurisdictional scheme volume charges ($/kWh) will apply to all controlled load tariffs. The rate for this volume charge is the same as the rate applied to the primary tariff. No jurisdictional scheme fixed charges apply to the controlled load tariffs.

### 6.3.5 Other changes compared to 2015–16 Pricing Proposal

In addition to the above changes, Ergon Energy has made a number of amendments to this Pricing Proposal. These include:

- refining the methodology used to calculate our avoidable and stand alone costs (refer to Section 4.8)
- refining our approach to LRMC in the setting of rates to apply to the cost reflective tariff structure parameters and rebalancing of existing parameters (refer to Section 4.9)
- considering the impact on transaction costs (refer to Section 4.10)
- considering the likelihood and ability of customers to respond to price signals (refer to Section 4.11)
- explicit consideration of churn from legacy tariffs to the LRMC-based tariffs (refer to Section 6.4)
- changing our approach to the customer count used in our DCOS Model for IBT and controlled load tariffs (refer to Section 6.4).

Finally, we have amended our SAC and EG network user group definitions. These definitions currently reference Australian Standard (AS) 4777. This standard presently captures inverters for energy systems up to 10 kVA on single phase and up to 30 kVA on three phase. In the future, AS 4777 is expected to capture inverters up to 200 kVA.

If the change proceeds, micro-embedded generators with inverters between 30 kVA and 200 kVA would move from our EG network user group into the SAC network user group. This means the current fixed charge which applies to the generation side of their connection would cease to apply. Given the size of the generation connected, this would lead to an increased risk of cross subsidy between customers without export and these customers.

To ensure a consistent and equitable approach across the regulatory control period, we have made reference to AS 4777.1 – 2005 in our SAC and EG network user group definitions. This is the standard that applied as at 1 July 2015. This means the generation side of micro-embedded generators with inverters between 30 kVA and 200 kVA will continue to be treated as an EG. The revised network user group definitions are included in the Glossary of this Pricing Proposal.

### 6.3.6 Compliance with regulatory obligations

Ergon Energy has demonstrated that the changes discussed in Section 6.3 comply with the NER and any applicable Distribution Determination throughout this Pricing Proposal. A summary of our compliance with these obligations is set out in Appendix 7.

## 6.4 Forecasting methodology

Clause 6.18.8(a)(2) of the NER requires that the AER must approve the Pricing Proposal if it is satisfied that all forecasts associated with the proposal are reasonable.

This section demonstrates how Ergon Energy considers that the forecasts used for pricing purposes are reasonable, having specific regard for the development of energy consumption, energy demand, customer numbers, customer churn and TUOS expense forecasts.

Ergon Energy annually prepares a one year forecast of customer numbers, demand and energy consumption for preparation of our Pricing Proposal. This forecast is done by network user group, with an initial forecast generally prepared in October of each year. This is later refined, typically in February and/or March of the following year, based on the most up to date information available prior to preparation of the annual Pricing Proposal.

The refined forecasts used for developing the prices are set out in Appendix 2 of this Pricing Proposal.

Our forecasts reflect significant uncertainties with regard to future volumes, including state government initiatives which may increase the uptake of renewable energy.

Major customers are forecast individually for energy consumption and maximum any-time demand. The energy forecast is based on a review of each customer's recent actual consumption history plus any confirmed future operational changes. The forecast for EGs is the amount of energy generated into Ergon Energy's distribution system. For ICCs and CACs, it is energy consumption that is being forecast.

The forecast demand for major customers is either:

- negotiated with the network user and detailed in their connection contract ('contracted demand')
- based on a review of actual demand history, with adjustments made for confirmed additions and losses of load.

For the SAC network user group, energy consumption and customer numbers are forecast for each customer group based on extrapolations of historical data. Demand is not measured or forecast, but customer group demands are calculated using appropriate load factors which are then used as allocators in the DCOS Model.

The customer groups are:

- SAC Large
- SAC Small
    - Residential
    - Business
    - Controlled Load
- SAC Unmetered.

For SAC Large, due to the relatively low number of customers, an actual count of the most recent historical data by customer was used as the basis for the forecast of both energy and customer numbers.

For SAC Small, customer numbers were classified as those connected customer premises with an active National Metering Identifier status. Since annual occupancy of the connected customer premises is less than 100 per cent, an adjustment was made in the DCOS Model when determining the fixed charge component for the IBT and controlled load tariffs.

Forecasts were prepared of the annual energy that would be consumed in each IBT block for residential and business customers, and also of energy that would be consumed in each TOU pricing segment (i.e. peak and off-peak).

For our STOUD tariffs, forecasts were prepared of the amount of energy that would be consumed in each TOU pricing segment (i.e. peak and off-peak). This was done by taking a sample of customers' chargeable quantities for demand and energy, and applying a scaling factor to enable the recovery of the revenue required. Scaling is applied to both the LRMC and residual charges.

As most customers will have the option of accessing a TOU variant tariff, and the net outcome would have different overall revenue implications, a forecast of the adoption of each tariff was required. In respect of the optional, demand-based tariffs, we noted in Section 2.3 our methodology for determining the rates for both legacy and optional tariffs, which estimates the impact of possible customer churn based on the cost reflective rates produced.

We also noted that, in future years, rates for volume-based and optional, demand-based tariffs will be calculated simultaneously. As part of this progression, we have applied this approach for CAC tariffs in 2016–17.

Ergon Energy's customer churn forecasts are contained in Appendix 2.

Annual TUOS payments are made to Powerlink, other DNSPs, and EGs for Avoided TUOS. The forecast of annual TUOS payments to Powerlink is based on preliminary TUOS prices provided by Powerlink in March 2016. Forecast energy, historical energy and nominated demand are applied to the TUOS prices to give forecast TUOS payments for each Transmission Connection Point:

- The energy forecast is prepared for each Transmission Connection Point, considering the impact of embedded generation, major customers supplied, and an extrapolation of the historical remaining General Cost Pool customer group. Adjustments for Distribution Loss Factors (DLFs) are taken into account where energy sales forecasts are used as the basis for the purchase forecast.
- The Powerlink nominated demand is the average of the ten highest daily demands between November and March each year at each Transmission Connection Point. This is forecast by applying the historical load factor to the forecast energy for each Transmission Connection Point.

Similarly, forecast TUOS payments to other DNSPs are based on rates provided by the DNSP and forecast energy and demand applicable to that supply. These energy and demand forecasts are provided by Ergon Energy to the DNSP for use in setting their network charges and are based on an extrapolation of historical data, while considering other known changes to the connection arrangement.

Forecast Avoided TUOS payments are based on the relevant EG's forecast export used within the Ergon Energy distribution network and the relevant transmission locational energy charge. The forecast export is based on historical demand, while considering the impact of confirmed new EG projects.

# Appendix 1: Table of network tariffs for Standard Control Services

This appendix sets out the 2016–17 network tariffs for:

- SACs
- CACs (excluding individual connection units and DLFs).

Site-specific network tariffs for ICCs and EGs, as well as the specific connection units and DLFs applying to each CAC, are provided in Appendix 2.

This appendix meets the following requirements of the NER:

- clause 6.18.2(b)(2) which requires Ergon Energy to set out the proposed tariffs for each tariff class
- clause 6.18.2(b)(3) which requires Ergon Energy to set out, for each proposed tariff, the charging parameters and the elements of service to which each charging parameter relates
- clause 6.18.9(a)(2) which requires Ergon Energy to maintain on our website for each tariff, the charging parameters and the elements of the service to which each charging parameter relates.

# Appendix 2: Standard Control Services pricing model

This confidential model provides the following information for the AER's consideration:

- calculation of the unders and overs accounts for DUOS, TUOS and jurisdictional scheme amounts
- the network tariff rates for 2016–17 and associated revenues and reconciliation
- our energy, load and customer number forecasts
- demonstration of how Ergon Energy meets the tests for avoidable and stand alone costs under clause 6.18.5 of the NER
- demonstration of how Ergon Energy meets the side constraints test under clause 6.18.6 of the NER.

# Appendix 3: Forecast weighted average revenue

This appendix sets out the forecast weighted average revenue for each Standard Control Service tariff class.

**Table A3.1: Weighted average revenue (GST Exclusive)**

| Tariff class | 2015-16 | 2016-17 |
|---|---:|---:|
| ICC – East | $40,090,199 | $39,702,415 |
| ICC – West | $14,481,689 | $13,822,956 |
| ICC – Mount Isa | $0 | $0 |
| CAC – East | $91,375,415 | $81,335,795 |
| CAC – West | $19,412,646 | $10,985,883 |
| CAC – Mount Isa | $0 | $0 |
| EG – East | $2,888,008 | $2,788,920 |
| EG – West | $238,471 | $257,559 |
| EG – Mount Isa | $0 | $0 |
| SAC Large (>100 MWh p.a.) – East | $305,022,852 | $316,055,456 |
| SAC Large (>100 MWh p.a.) – West | $84,394,130 | $86,055,625 |
| SAC Large (>100 MWh p.a.) – Mount Isa | $4,339,957 | $4,558,554 |
| SAC Small (<100 MWh p.a.) – East | $662,780,511 | $677,514,001 |
| SAC Small (<100 MWh p.a.) – West | $199,292,606 | $197,865,198 |
| SAC Small (<100 MWh p.a.) – Mount Isa | $10,065,088 | $10,680,168 |
| SAC Unmetered – East | $17,143,027 | $18,395,701 |
| SAC Unmetered – West | $2,197,956 | $2,681,502 |
| SAC Unmetered – Mount Isa | $326,377 | $312,679 |

# Appendix 4: Alternative Control Services tariffs

This appendix sets out the tariffs applicable to Alternative Control Services in 2016–17.

All prices in this appendix are GST Exclusive.

## Fee based services

### Table A4.1: Fee based services prices

| Service | 2016-17 GST Exclusive | |
|---|---|---|
| | Total price [a] | Call out fee [b] |
| Application fee - Basic or standard connection | $870.18 | n/a |
| Application fee - Basic or standard connection - Micro-embedded generators | $47.60 | n/a |
| Application fee - Basic or standard connection - Micro-embedded generators - Technical assessment required | $216.17 | n/a |
| Application fee - Real estate development connection | $911.10 | n/a |
| Protection and Power Quality assessment prior to connection | $1,348.46 | n/a |
| Temporary connection, not in permanent position - single phase metered - urban/short rural feeders | $572.95 | $114.59 |
| Temporary connection, not in permanent position - single phase metered - long rural/isolated feeders | $916.72 | $458.36 |
| Temporary connection, not in permanent position - multi phase metered - urban/short rural feeders | $572.95 | $114.59 |
| Temporary connection, not in permanent position - multi phase metered - long rural/isolated feeders | $916.72 | $458.36 |
| Supply abolishment during business hours - urban/short rural feeders | $343.77 | $114.59 |
| Supply abolishment during business hours - long rural/isolated feeders | $687.54 | $458.36 |
| De-energisation during business hours - urban/short rural feeders | $96.01 | $38.17 |
| De-energisation during business hours - long rural/isolated feeders | $572.95 | $458.36 |
| Re-energisation during business hours - urban/short rural feeders | $76.35 | $38.17 |
| Re-energisation during business hours - long rural/isolated feeders | $533.99 | $458.36 |
| Re-energisation during business hours - after de-energisation for debt - urban/short rural feeders | $76.35 | $38.17 |
| Re-energisation during business hours - after de-energisation for debt - long rural/isolated feeders | $533.99 | $458.36 |
| Accreditation of alternative service providers - real estate developments | $884.93 | n/a |
| Install new or replacement meter (Type 5 and 6) - Single phase - urban/short rural feeder | $338.15 | $62.13 |
| Install new or replacement meter (Type 5 and 6) - Single phase - long rural/isolated feeder | $524.25 | $248.53 |
| Install new or replacement meter (Type 5 and 6) - Dual element - urban/short rural feeder | $414.17 | $62.13 |
| Install new or replacement meter (Type 5 and 6) - Dual element - long rural/isolated feeder | $600.27 | $248.53 |
| Install new or replacement meter (Type 5 and 6) - Polyphase - urban/short rural feeder | $520.59 | $62.13 |

| Service | 2016-17 GST Exclusive Total price [a] | Call out fee [b] |
|---|---|---|
| Install new or replacement meter (Type 5 and 6) - Polyphase - long rural/isolated feeder | $706.69 | $248.53 |
| Install new or replacement meter (CT) - urban/short rural feeder | $2,473.23 | $118.88 |
| Install new or replacement meter (CT) - long rural/isolated feeder | $2,829.31 | $475.53 |

**Notes:**

a. Service undertaken.
b. No service undertaken due to customer/retailer fault.

## Quoted services

It is important to note that the prices set out below are examples of potential prices for our quoted services. This is because the actual prices for quoted services will be determined at the time of the requestor's enquiry and will reflect the actual requirements of the service.

Further, where Ergon Energy attends a premises to perform a service and is unable to complete the work order for reasons outside our control, such as a locked gate, we will charge a call out fee.

**Table A4.2: Potential quoted services prices**

| Service | 2016-17 GST Exclusive |
|---|---|
| Application fee - Negotiated connection | $1,106.89 |
| Application fee - Negotiated connection - Micro-embedded generators | $491.74 |
| Application fee - Negotiated - Major customer connection | $7,078.02 |
| Carrying out planning studies and analysis relating to connection applications | $2,235.91 |
| Feasibility and concept scoping, including planning and design, for major customer connections | $17,981.16 |
| Tender process | $10,467.92 |
| Pre-connection site inspection | $1,297.77 |
| Provision of site-specific connection information and advice | $765.56 |
| Preparation of preliminary designs and planning reports for major customer connections, including project scopes and estimates | $9,421.13 |
| Customer build, own and operate consultation services | $74,618.80 |
| Detailed enquiry response fee - embedded generation | $24,943.32 |
| Design and construction of connection assets for major customers | $8,866,367.57 |
| Commissioning and energisation of major customer connections | $43,058.66 |
| Design and construction for real estate developments | $169,203.36 |
| Commissioning and energisation of real estate development connections | $6,769.39 |
| Removal of network constraint for embedded generator | $542,736.39 |
| Move point of attachment - single/multi phase | $3,648.49 |
| Re-arrange connection assets at customer's request | $65,860.89 |
| Protection and Power Quality assessment after connection | $2,787.65 |
| Temporary de-energisation - no dismantling | $728.17 |
| LV Service line drop and replace - physical dismantling | $1,055.53 |
| HV Service line drop and replace | $4,456.70 |
| Supply enhancement | $1,273.98 |

| Service | 2016-17 GST Exclusive |
|---|---|
| Provision of connection services above minimum requirements | $300,068.02 |
| Upgrade from overhead to underground service | $8,593.83 |
| Rectification of illegal connections or damage to overhead or underground service cables | $214.92 |
| De-energisation after business hours | $141.27 |
| Re-energisation after business hours | $112.33 |
| Accreditation of alternative service providers - major customer connections | $6,265.80 |
| Approval of third party design - major customer connections | $13,957.22 |
| Approval of third party design - real estate developments | $196.40 |
| Construction audit - major customer connections | $90,562.64 |
| Construction audit - real estate developments | $1,152.66 |
| Approval of third party materials | $18,765.73 |
| Special meter read | $125.50 |
| Meter test | $444.17 |
| Meter inspection and investigation on request | $286.56 |
| Metering alteration | $2,833.45 |
| Exchange meter | $286.56 |
| Type 5 to 7 non-standard metering services | $406.32 |
| Removal of a meter (Type 5 & 6) | $135.00 |
| Meter re-seal | $580.28 |
| Install new or replacement meter - after hours | $414.43 |
| Change time switch | $214.92 |
| Change tariff | $222.08 |
| Reprogram card meters | $1,289.52 |
| Install metering related load control | $286.56 |
| Removal of load control device | $286.56 |
| Change load control relay channel | $143.28 |
| Services provided in relation to a Retailer of Last Resort (ROLR) event | $2,807.65 |
| Non-standard network data requests | $697.86 |
| Provision of services for approved unmetered supplies | $101.75 |
| Customer or retailer requested appointments | $742.27 |
| Removal/rearrangement of network assets | $305,207.01 |
| Aerial markers | $722.09 |
| Tiger tails | $2,438.50 |
| Assessment of parallel generator applications | $1,744.65 |
| Witness testing | $3,849.24 |
| Removal/rearrangement of public lighting assets | $20,791.76 |

## Default Metering Services

### Table A4.3: Annual metering services charges

| Metering service type | Cost recovery type | 2016-17 Fixed charge ($ p.a.) GST Exclusive |
|---|---|---|
| Primary | Non–capital | $42.03 |
| | Capital | $10.23 |
| Controlled load | Non–capital | $15.45 |
| | Capital | $3.76 |
| Embedded generation | Non–capital | $10.45 |
| | Capital | $2.55 |

### Table A4.4: Call out fees for final meter reads

| Meter | 2016-17 Fixed charge ($/call out) GST Exclusive |
|---|---|
| Call out fee - Final meter read - Urban/short rural feeder | $53.54 |
| Call out fee - Final meter read - Long rural/isolated feeder | $214.16 |

## Public Lighting Services

### Table A4.5: Daily public lighting charges

| Public Lighting Services | 2016-17 Fixed charge ($/day/light) GST Exclusive |
|---|---|
| EO&O - Major | $1.0896 |
| EO&O - Minor | $0.6492 |
| G&EO - Major | $0.4400 |
| G&EO - Minor | $0.2882 |

### Table A4.6: Public lighting exit fees

| Public lighting exit fee | 2016-17 Fixed charge ($/light) GST Exclusive |
|---|---|
| EO&O - Major - Exit fee | $1,438 |
| EO&O - Minor - Exit fee | $869 |
| G&EO - Major - Exit fee | $238 |
| G&EO - Minor - Exit fee | $202 |

# Appendix 5: Alternative Control Services pricing models

These confidential models provide quantitative information to demonstrate the calculation of our prices for Alternative Control Services.

# Appendix 6: Expected price trends

This appendix sets out indicative prices for 2017–18 to 2019–20 for our:

- Standard Control Services (DUOS charges)
- TUOS charges
- Jurisdictional scheme charges
- Alternative Control Services.

Indicative prices will be recalculated each year. All prices in this appendix are GST Exclusive.

# Appendix 7: Compliance matrix

Ergon Energy's compliance with the NER and the AER's Distribution Determination is set out in Part 2 of this Pricing Proposal. For ease of reference, a summary of the obligations and how we have demonstrated compliance in this Pricing Proposal is provided below.

### Table A7.1: Compliance obligations under the NER

| Clause | Obligation | Demonstration of compliance in this Pricing Proposal |
|---|---|---|
| 6.18.2(b)(1) | Set out each tariff class (including the classes of Alternative Control Services). | Tariff classes are set out and justified in Sections 4.1 and 5.1. |
| 6.18.2(b)(2) | Set out the proposed tariffs for each tariff class. | Tariff schedules for Standard Control Services are set out in Appendix 1 and Appendix 2. These tariffs reflect the changes proposed to each of our network user groups, which are set out in Section 6.3.3.<br><br>Tariff schedules for Alternative Control Services are provided in Appendix 4. There are a number of new services in 2016–17 following the release of the Distribution Determination on 29 October 2015. Refer to Section 6.3.1 for a summary of these changes. |
| 6.18.2(b)(3) | Set out the charging parameters and the elements of service to which each charging parameter relates. | For Standard Control Services, details of the charging parameters and the elements of the service to which each relates are set out in Section 4.2.<br>For Alternative Control Services, the charging parameters are fixed by the control mechanism imposed by the AER. There are two broad types of charges (fixed charges and quoted prices), with several charging parameters. Refer to Section 8 of our TSS. |
| 6.18.2(b)(4) | Set out the expected weighted average revenue for each tariff class related to Standard Control Services. | Weighted average revenue calculations for each Standard Control Service tariff class are set out in Appendix 3. |
| 6.18.2(b)(5) | Set out the nature of any variation or adjustment to the tariff that could occur during the course of the regulatory year and the basis on which it could occur. | Variations and adjustments which could apply to tariffs during 2016–17 are set out in Section 6.2. |
| 6.18.2(b)(6) and 6.18.7 | Set out how designated pricing proposal charges incurred by distributors for TUOS services are to be passed through to customers and any adjustments to tariffs resulting from over or under recovery of those charges in the previous regulatory year. | The method of passing through designated pricing proposal charges (TUOS) to customers is addressed in Section 4.12. |
| 6.18.2(b)(6A) | Set out how jurisdictional scheme amounts for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from the over or under recovery of those amounts. | The method of passing through jurisdictional scheme amounts to customers is addressed in Section 4.13. |
| 6.18.2(b)(6B) | Describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria. | There have been no changes to the jurisdictional schemes since their last jurisdictional scheme approval dates. Section 4.13.2 provides further details. |

| Clause | Obligation | Demonstration of compliance in this Pricing Proposal |
|---|---|---|
| 6.18.2(b)(7) | Demonstrate compliance with the NER and any applicable distribution determination. | This table and Table A7.2 demonstrate how Ergon Energy complies with the NER and the Distribution Determination. |
| 6.18.2(b)(8) | Describe the nature and extent of change from the previous regulatory year and demonstrate that the changes comply with the NER and any applicable Distribution Determination. | There have been some changes to pricing arrangements as a result of the Distribution Determination. These changes are set out in Section 6.3.1.<br>Ergon Energy is also proposing a number of changes to our Standard Control Services, Alternative Control Services and jurisdictional scheme charges from 1 July 2016. Variations and adjustments incorporated into this year's Pricing Proposal as a result of these changes are set out in Sections 6.3.2 to 6.3.5.<br>How these changes comply with the NER and any applicable Distribution Determination is set out in this table and Table A7.2. |
| 6.18.3(a) | Define the tariff classes into which customers for Direct Control Services are divided. | Tariff classes applicable to customers for Direct Control Services are set out and justified in Sections 4.1 and 5.1. |
| 6.18.3(b) | Demonstrate that each customer for Direct Control Services is a member of at least one tariff class. | Assignment of each customer to a tariff class is demonstrated in Sections 4.1 and 5.1. |
| 6.18.3 (c) | Set out separate tariff classes for Standard Control Services and Alternative Control Services. | Tariff classes for Standard and Alternative Control Services are set out in Sections 4.1 and 5.1, respectively. |
| 6.18.3(d)(1) | Demonstrate that tariff classes are formed based on groupings of customers on an economically efficient basis. | A description of how tariff classes group customers on an economically efficient basis is set out in Sections 4.1 and 5.1.<br>Default Metering Services and Public Lighting Services are provided to customers who require those services and grouping is undertaken on this basis. |
| 6.18.3(d)(2) | Demonstrate that customers and tariffs are grouped into tariff classes with regard to the need to avoid unnecessary transaction costs. | A description of how tariffs are grouped into tariff classes with regard to the need to avoid unnecessary transaction costs is set out in Sections 4.1 and 5.1.<br>Default Metering Services and Public Lighting Services are provided to customers who require those services and grouping is undertaken on this basis. |
| 6.18.5(a)(1) and (2) | Demonstrate that revenue from a tariff class lies on or between the stand alone and avoidable cost. | Stand alone and avoidable cost assessments are provided in Sections 4.8 and 5.5. We have further refined our approach to calculating the stand alone costs in 2016–17. The calculation of these estimates for Standard Control Services is provided in Appendix 2. |
| 6.18.5(b)(1) | Demonstrate that tariffs and charging parameters have regard for Long Run Marginal Cost (LRMC). | LRMC is dealt with in Sections 4.9 and 5.6. We are progressively increasing the LRMC signals in the distribution component of our network tariffs. |

| Clause | Obligation | Demonstration of compliance in this Pricing Proposal |
|---|---|---|
| 6.18.5(b)(2)(i) | Demonstrate that tariffs and charging parameters have been determined having regard to the transaction costs associated with the tariff or each charging parameter. | We have had regard to transaction cost impacts from our tariffs, particularly in the context of the changes to our network tariff structures in 2016–17. Complexity may increase transaction costs. However, because many of the demand-based tariffs are optional, customers will have a choice in whether to adopt these tariffs or remain on legacy tariffs with lower transaction costs.<br><br>Further information on tariffs and transaction costs is contained in Sections 4.10 and 5.6. |
| 6.18.5(b)(2)(ii) | Demonstrate that tariffs and charging parameters are set with regard to whether customers will respond to signals. | Tariffs and signals are dealt with in Sections 4.11 and 5.6. |
| 6.18.5(c) | Demonstrate that if tariffs do not recover the required revenue as a result of the operation of 6.18.5(b), that tariffs have been adjusted with minimum distortion. | This is dealt with in Section 6.1. |
| 6.18.6 (a) and (b) | Demonstrate that the weighted average revenue for a Standard Control Service tariff class does not exceed that for the previous year by more than the "permissible percentage" defined in 6.18.6(c) of the NER. | Side constraints are dealt with in Section 4.7. |
| 6.18.6(c)(1) and (2) | Demonstrate the "permissible percentage" has been calculated in accordance with the definition set out in this clause of the NER. | Side constraints are dealt with in Section 4.7. |
| 6.18.6(d)(1), (2) and (3) | Demonstrate that designated pricing proposal charges (TUOS), pass throughs and jurisdictional scheme amounts were removed from the calculation of the side constraint. | Side constraints are dealt with in Section 4.7. |
| 6.18.6(e) | Demonstrate that the side constraints have not impacted on the extent to which the tariffs for a customer with remotely read interval metering will vary according to usage. | Side constraints are dealt with in Section 4.7. |
| 6.18.7(a) | Demonstrate that the tariffs passed on, to customers, the designated pricing proposal charges (TUOS) to be incurred by Ergon Energy for TUOS services. | Designated pricing proposal charges (TUOS) passed on to customers are dealt with in Section 4.12. |
| 6.18.7(b) | Demonstrate that the designated pricing proposal charges (TUOS) passed on to customers do not exceed the forecast charges adjusted for over or under recovery. | Designated pricing proposal charges (TUOS) passed on to customers are dealt with in Section 4.12. |
| 6.18.7(c)(1), (2) and (3) | Demonstrate that any designated pricing proposal charges (TUOS) over or under recovery, being the difference between the amount actually paid and what was recovered from customers via TUOS charges, is consistent with the Final Determination and adjusts for the appropriate cost of capital. | Designated pricing proposal charges (TUOS) passed on to customers are dealt with in Section 4.12. |
| 6.18.7A (a), (b) and (c) | Demonstrate that tariffs passed on, to customers, the jurisdictional scheme amounts to be incurred by Ergon Energy for approved jurisdictional schemes in accordance with 6.18.7A of the NER. | Our approach to applying jurisdictional scheme amounts to customer tariffs is provided in Section 4.13.3. |

| Clause | Obligation | Demonstration of compliance in this Pricing Proposal |
|---|---|---|
| 6.18.8(a)(2) | Demonstrate that all forecasts associated with the proposal are reasonable. | Ergon Energy has made some changes to tariff structures and introduced new tariff components in 2016–17. We have also changed our approach to the customer count used in our DCOS Model for IBT and controlled load tariffs.<br>Nevertheless, the methodology used to forecast customer numbers, energy consumption, demand and TUOS payments is consistent with the overarching method used by Ergon Energy in 2015–16.<br>Further information is contained in Section 6.4. |
| 6.18.9(a)(1) | Demonstrate that tariffs classes and the tariffs applicable to each class are maintained on Ergon Energy's website. | This Pricing Proposal, including non-confidential appendices, will be published on Ergon Energy's website. |
| 6.18.9(a)(2) | Demonstrate that charging parameters are maintained on Ergon Energy's website. | This Pricing Proposal, including non-confidential appendices, will be published on Ergon Energy's website. |
| 6.18.9(a)(3) | Demonstrate that Ergon Energy maintains on its website a statement of expected price trends (to be updated each regulatory year) giving an indication of how it expects prices to change over the regulatory control period and the reasons for the expected changes. | The expected price trends are set out in Appendix 6 and will be published separately on our website. |
| 6.18.9(b) | Demonstrate that the posting of information for a particular regulatory year must, if practicable, be posted on Ergon Energy's website 20 business days before the commencement of the relevant regulatory year and, if that is not practicable, as soon as practicable thereafter. | This Pricing Proposal will be published on Ergon Energy's website by the appropriate date.<br>Ergon Energy's supporting network pricing documentation, as set out in Section 1.4, will also be published on our website. |

### Table A7.2: Compliance with the Distribution Determination

| Obligation | Demonstration of compliance in this Pricing Proposal |
|---|---|
| Demonstrate that our revenue is consistent with the TAR formula set out in Figure 14.1 of Attachment 14 of the Distribution Determination. | This is demonstrated in Section 4.5 and Appendix 2. |
| For Standard Control Services, apply the X factor for each year of the regulatory control period as determined in the PTRM and annually revised for the return on debt update in accordance with the formula specified in Attachment 3 – rate of return – of the Distribution Determination. | In 2016–17, Ergon Energy has applied the X factor provided by the AER on 23 March 2016 in its amended PTRM. |
| Calculate the DMIS adjustment using the method set out in the DMIS and add or deduct this amount from the TAR in 2016–17. | Ergon Energy has applied the DMIS carryover amount provided by the AER on 1 April 2016. |
| Demonstrate the side constraints applying to the price movements of each tariff class are consistent with the formula in Figure 14.2 of Attachment 14 of the Distribution Determination. | Side constraints are dealt with in Section 4.7. We have applied the formula set out in the Distribution Determination. |
| Maintain a DUOS unders and overs account in accordance with appendix A of Attachment 14 of the Distribution Determination. The expected closing balance at the end of each regulatory year t should be as close as practicable to zero. | Our DUOS unders and overs account is set out in Section 4.5.2. This section also details the unders/overs adjustment needed to move the balance of the DUOS unders and overs account to, as close as practical, zero. |

| Obligation | Demonstration of compliance in this Pricing Proposal |
|---|---|
| Maintain a TUOS unders and overs account in accordance with appendix B of Attachment 14 of the Distribution Determination. The expected closing balance at the end of each regulatory year t should be as close as practicable to zero. | Our TUOS unders and overs account is set out in Section 4.12.3. This section details the revenue to be recovered from TUOS charges and the unders/overs adjustment needed to move the balance of the TUOS unders and overs account to, as close as practical, zero. |
| Maintain a jurisdictional scheme unders and overs account in accordance with appendix C of Attachment 14 of the Distribution Determination. The expected closing balance at the end of each regulatory year t should be as close as practicable to zero. | Our jurisdictional scheme unders and overs account is set out in Section 4.13.3. This section details the jurisdictional scheme amount we expect to recover from customers in 2016–17 and the unders/overs adjustment needed to move the balance of the jurisdictional scheme unders and overs account to, as close as practical, zero.<br>We have amended the jurisdictional scheme unders and overs account since 2015–16 to take into account the energy industry levy. |
| Set out how we will review and assess the basis on which a customer is charged, where the charging parameters for a particular tariff result in a basis of charge that varies according to the customer's usage or load profile. | Our compliance with this obligation is dealt with in Sections 4.3 and 5.2. |
| Apply the public lighting formula set out in Figure 16.1 of Attachment 16 of the Distribution Determination to determine public lighting charges. | Our compliance with the public lighting formula is demonstrated in Appendix 5. |
| Apply the fee based ancillary network services formula set out in Figure 16.2 of Attachment 16 of the Distribution Determination to determine prices for fee based services. | Our compliance with the fee based ancillary network services formula is demonstrated in Appendix 5.<br>Note Ergon Energy has calculated prices for our fee based services using the cost build-up formula for quoted services and the fee based ancillary network services formula. For each fee based service, the price proposed in this Pricing Proposal is the lower of these two amounts. |
| Apply the quoted services formula set out in Figure 16.3 of Attachment 16 of the Distribution Determination to determine prices for quoted services. | Our compliance with the quoted services formula, for our illustrative examples, is demonstrated in Appendix 5.<br>In practice, we will develop a user-specific quote based on the requestor's needs. This will be determined using the quoted services formula. |
| Apply the price cap formula set out in section 16.3.1.3 of Attachment 16 of the Distribution Determination to determine prices for Default Metering Services. | Our compliance with the price cap formula for Default Metering Services is demonstrated in Appendix 5. |

# Glossary

## Abbreviations

| | |
|---|---|
| **ABS** | Australian Bureau of Statistics |
| **AEMC** | Australian Energy Market Commission |
| **AER** | Australian Energy Regulator |
| **AS** | Australian Standard |
| **ATMD** | Any Time Maximum Demand |
| **CAC** | Connection Asset Customer |
| **CAM** | Cost Allocation Method |
| **Capex** | Capital expenditure |
| **CPI** | Consumer Price Index |
| **CT** | Current transformer |
| **DCOS** | Distribution Cost of Supply |
| **DLF** | Distribution Loss Factor |
| **DMIS** | Demand Management Incentive Scheme |
| **DNSP** | Distribution Network Service Provider |
| **DPPC** | Designated pricing proposal charge |
| **DUOS** | Distribution Use of System |
| **EDNC** | Electricity Distribution Network Code |
| **EEQ** | Ergon Energy Queensland Pty Ltd |
| **EG** | Embedded Generator |
| **Energex** | Energex Limited |
| **Ergon Energy** | Ergon Energy Corporation Limited |
| **Excess kVAr** | Excess reactive power charge |
| **FiT** | Feed-in tariff |
| **GWh** | Gigawatt hour |
| **HV** | High voltage |
| **IBT** | Inclining Block Tariff |
| **ICC** | Individually Calculated Customer |
| **kV** | Kilovolt |
| **kVA** | Kilovolt-ampere |
| **kVAr** | Kilovolt-ampere reactive |
| **kW** | Kilowatt |
| **kWh** | Kilowatt hour |
| **Law** | National Electricity Law |
| **LED** | Light emitting diode |
| **LOB** | Line of Business |
| **LRMC** | Long Run Marginal Cost |
| **LV** | Low voltage |

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|---|---|
| **MWh** | Megawatt hour |
| **NEM** | National Electricity Market |
| **NER** | National Electricity Rules |
| **Opex** | Operating expenditure |
| **p.a.** | Per annum |
| **PTRM** | Post Tax Revenue Model |
| **PV** | Photovoltaic |
| **QCA** | Queensland Competition Authority |
| **QPC** | Queensland Productivity Commission |
| **RIN** | Regulatory Information Notice |
| **SAC** | Standard Asset Customer |
| **SPARQ** | SPARQ Solutions Pty Ltd |
| **STOUD** | Seasonal Time-of-Use Demand |
| **STOUE** | Seasonal Time-of-Use Energy |
| **STPIS** | Service Target Performance Incentive Scheme |
| **TAR** | Total Annual Revenue |
| **TNSP** | Transmission Network Service Provider |
| **TOU** | Time-of-Use |
| **TSS** | Tariff Structure Statement |
| **TUOS** | Transmission Use of System |
| **WACC** | Weighted Average Cost of Capital |

## Definitions

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| **Alternative Control Service** | A distribution service provided by Ergon Energy that the AER has classified as an Alternative Control Service under the NER. Includes fee based services, quoted services, Default Metering Services and Public Lighting Services. |
| **Annual revenue adjustment** | Annual adjustments made to Ergon Energy's smoothed revenue requirement for Standard Control Services for matters such as out-turn inflation, the return on debt, STPIS, pass throughs, and the difference between forecast and actual revenue received for DUOS charges. |
| **Any time energy** | Is the amount of energy consumed by the customer irrespective of the time of day. |
| **Any Time Maximum Demand (ATMD)** | Is the maximum half hourly demand for a customer that occurs at any time within a specified period. |
| **Australian Energy Market Commission (AEMC)** | The AEMC is the rule maker and developer for Australian energy markets. As a national, independent body they make and amend the detailed rules for the National Electricity Market (NEM) and elements of natural gas markets. |

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| **Australian Energy Regulator (AER)** | The AER is an independent statutory authority that is part of the Australian Competition and Consumer Commission. The AER is responsible for the economic regulation of electricity networks in the NEM. It also monitors the wholesale electricity and gas markets and is responsible for compliance with and enforcement of the Law, NER, National Gas Law and Rules, and the National Energy Retail Law and Rules. |
| **Authorised demand** | The maximum demand permitted to be imported or exported to the network by a network user, based on the nature of their connection. The authorised demand is either:<br>• negotiated with the network user and detailed in their connection contract<br>• determined by Ergon Energy as part of the annual price setting process, using historical data. |
| **Avoided TUOS** | The amount paid to an eligible EG for the locational component of prescribed TUOS services that would have been payable by Ergon Energy to a TNSP had the EG not been connected to the distribution network. The methodology Ergon Energy uses to comply with the NER is set out in the *Information Guide for Standard Control Services Pricing*. |
| **Business customer** | Means a customer who is not a residential customer (as defined in the Queensland Electricity Distribution Network Code (EDNC)). |
| **Capacity charge** | A type of charge (charging parameter) included in Ergon Energy's network tariff structures. The capacity charge is reflective of the costs associated with the network capacity required by a customer on a long term basis. |
| **Capital contribution** | A capital contribution is a prepayment for the provision of Direct Control Services. A capital contribution may be charged to a customer if the new connection or modification for an existing connection is required to the network to accommodate the connection/modification. Ergon Energy's Connection Policy sets out circumstances in which a capital contribution may be required and details how the capital contribution to be charged to a customer is calculated. |
| **Charging parameter** | The constituent elements of a tariff (as defined in the NER). |
| **Connection** | The physical link to or through a transmission network or distribution network. |

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| **Connection Asset Customer (CAC)** | Typically reflects those customers:<br>• with required capacity above 1,500 kVA<br>• with energy consumption typically greater than 4 GWh p.a. (but less than 40 GWh p.a.), or<br>• with required capacity below 1,500 kVA where:<br>  ○ a customer has a dedicated supply system which is quite different and separate from the remainder of the supply network, or<br>  ○ inequitable treatment of otherwise comparable customers will arise from the application of the 4 GWh p.a. threshold.<br>The CAC group is further subdivided into categories based on voltage levels as follows:<br>• 66 kV – connected to either a 66 kV substation or a 66 kV line<br>• 33 kV – connected to either a 33 kV substation or a 33 kV line<br>• 22/11 kV Bus – connected to either a 22 kV or 11 kV substation<br>• 22/11 kV Line – connected to either a 22 kV or 11 kV line. |
| **Connection assets** | Those components of a transmission or distribution system which are used to provide connection services. Connection assets are those assets required to connect an electrical installation to the shared network and are all the assets from the connection point back up to and including the network coupling point. |
| **Connection point** | The agreed point of supply established between the Network Service Provider(s) and another Registered Participant, Non-Registered Customer or franchise customer. |
| **Customer** | A person or entity that receives, or wants to receive a supply of electricity for a premises, or any other distribution service from Ergon Energy. |
| **Default Metering Services** | A type of Alternative Control Service. Relates to:<br>• Type 5 and 6 meter installation and provision (before 1 July 2015)<br>• Type 5 and 6 meter installation and provision (on or after 1 July 2015), where the replacement meter is initiated by Ergon Energy as a distributor<br>• Type 5 and 6 metering maintenance, reading and data services. |
| **Demand** | The amount of electricity energy being consumed at a given time measured in either watts (W) or volt amperes (VA). The difference between the two is the power factor. |

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| **Demand charges** | A type of charge (charging parameter) included in Ergon Energy's network tariff structures. Within a tariff structure, demand charge rates can be:<br>• applied year round or seasonally (with different peak and off-peak rates)<br>• calculated based on:<br>  ○ a single period in the month<br>  ○ the maximum demand within a peak demand window<br>  ○ an average of demands within a demand window.<br>Some tariff structures include a floor (the demand charge must include at least the rate times 'X' demand) or a threshold (the demand charge is only calculated for demand recorded above a particular level). |
| **Designated pricing proposal charges (DPPC)** | Typically referred to as 'TUOS' in this Pricing Proposal. See the 'Transmission Use of System (TUOS) charge' definition below. |
| **Direct Control Service** | Distribution services subject to economic regulation by the AER under the NER. Direct Control Services are further subdivided into Standard Control Services and Alternative Control Services. |
| **Distribution Cost of Supply (DCOS) Model** | The Ergon Energy model used to allocate costs to network users and convert the revenue cap, transmission-related costs and jurisdictional scheme amounts into network tariffs. |
| **Distribution Determination** | The AER's Distribution Determination sets the revenue and pricing control regime that Ergon Energy must comply with for the current regulatory control period (i.e. 2015–20). |
| **Distribution network** | The electrical system used to transport electricity from the high voltage transmission network connection point to distribution network users. |
| **Distribution Use of System (DUOS) charge** | Component of the network tariffs which recovers costs associated with connection services and/or use of the distribution network for the conveyance of electricity (i.e. Standard Control Services). |
| **East Zone** | Those areas where the network users are supplied from the distribution system connection to the national grid and have a relatively low distribution cost to supply. The local government areas covered by the East Zone are located in the *Information Guide for Standard Control Services*. |
| **Electricity Market** | Means the NEM as administered by the Australian Energy Market Operator. |
| **Embedded Generator (EG)** | EGs are those network users that export energy into the distribution system, except for network users with micro-generation facilities of the kind contemplated under AS 4777.1 – 2005.<br>EGs are separated into two categories:<br>• EGs that are connected to the distribution system and only generate into the distribution system<br>• EGs that are connected to the distribution system, generate and take load from the system.[36] |

36 The load side will be classified as an ICC, CAC or SAC, and a separate network tariff will apply.

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| **Energy** | The amount of electricity consumed by a customer (or all customers) over a period of time. Energy is measured in terms of watt hours (Wh), kilowatt hours (kWh), megawatt hours (MWh) or gigawatt hours (GWh). |
| **Excess reactive power charge (Excess kVAr)** | A type of charge (charging parameter) included in Ergon Energy's network tariff structures which is applied against the kVAr used by a customer that exceeds what they would be entitled to use at their minimum compliant power factor at authorised demand. |
| **Fee based services** | A type of Alternative Control Service which Ergon Energy undertakes at the request of an identifiable customer, retailer or appropriate third party which is levied as a separate charge. The costs of providing the service (and therefore price) can be assessed in advance of the service being requested. |
| **Fixed charge** | A type of charge (charging parameter) included in Ergon Energy's network tariff structures which is levied on a fixed dollar amount per day or fixed dollar amount per day per device (as is the case for unmetered supply). |
| **Gigawatt hour (GWh)** | 1,000,000 kilowatt hours. |
| **High Voltage (HV)** | Refers to parts of the network that are 11 kV or above. |
| **Inclining Block Tariff (IBT)** | A type of network tariff where the price per kWh increases as consumption thresholds are crossed during a particular time period. |
| **Individually Calculated Customer (ICC)** | Typically reflects those customers:<br>• with energy consumption typically greater than 40 GWh p.a., or<br>• with energy consumption lower than 40 GWh p.a. where:<br>  ○ a customer has a dedicated supply system which is quite different and separate from the remainder of the supply network<br>  ○ there are only two or three customers in a supply system, making average prices inappropriate<br>  ○ a customer is connected at or close to a Transmission Connection Point, or<br>  ○ inequitable treatment of otherwise comparable customers will arise from the application of the 40 GWh p.a. threshold. |
| **Isolated generation** | Those areas supplied from Ergon Energy's isolated generation assets, except for the Mount Isa system. Includes communities in Western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait Islands, Palm Island and Mornington Islands. These areas are not subject to economic regulation by the AER, but are regulated by the Queensland Government. |
| **Jurisdictional scheme amount** | In respect of a jurisdictional scheme, the amounts a DNSP is required under the jurisdictional scheme obligations to:<br>(a) pay to a person<br>(b) pay into a fund established under an Act of a participating jurisdiction<br>(c) credit against charges payable by a person, or<br>(d) reimburse a person,<br>less any amounts recovered by the DNSP from any person in respect of those amounts other than under the NER (as defined in the NER). |

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| **Jurisdictional scheme charges** | Component of the network tariff which passes through jurisdictional scheme amounts. |
| **kVA** | 1,000 Volt-Ampere which is a measure of the apparent power flow which is a measure of the total capacity required to supply a customer's load. |
| **kVAr** | 1,000 Volt-Ampere reactive which is a measure of reactive power. |
| **kW** | 1,000 Watts which is a measure of the real component of power being consumed by the consumer's load. |
| **Load factor** | Measure of the percentage of time a load is used in any given period. Loads used 24 hours per day, 7 days a week have a load factor of one (1) or 100 per cent. |
| **Long Run Marginal Cost (LRMC)** | The cost of an incremental change in demand over a period of time in which all factors of production required to provide those services can be varied (as defined in the NER).<br>This definition incorporates the investment required over time to maintain and expand capacity in the network to meet future demand. |
| **Low Voltage (LV)** | Refers to the sub 11 kV network. |
| **Major customer** | Are ICCs, CACs or EGs. |
| **Maximum demand** | The maximum demand recorded at a customer's individual meter or the maximum demand placed on the electrical distribution network system at any time or at a specific time or within a specific time period, such as a month. Maximum demand is an indication of the capacity required for a customer's connection or the electrical distribution network. |
| **Megawatt hour (MWh)** | 1,000 kilowatt hours |
| **Mount Isa Zone** | Those areas supplied from the isolated Mount Isa system. This zone is not connected to the national grid and would normally be excluded from the application of the NER. However, under the *Electricity – National Scheme (Queensland) Act 1997,* the Queensland Government has transferred responsibility for the economic regulation of the Mount Isa-Cloncurry supply network to the AER. The local government areas covered by the Mount Isa Zone are located in the *Information Guide for Standard Control Services*. |
| **National Electricity Market (NEM)** | The interconnected electricity grid covering Queensland, New South Wales, Victoria, Tasmania, South Australia and the Australian Capital Territory. |
| **National Electricity Rules (NER)** | Rules made under the Law which govern the operation of the NEM. |
| **Network capacity** | The maximum demand (kW) that the distribution network can provide for at any one time. |
| **Network coupling point** | The point at which connection assets join a distribution network, used to identify the distribution service price payable by a connection customer. |
| **Network tariff** | Refers to the price (or tariff) that Ergon Energy sets to recover costs associated with the customer's connection and use of the distribution and transmission network, and jurisdictional scheme amounts. Network tariffs comprise DUOS, TUOS and jurisdictional scheme charges. |

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| **Network user** | There are four network user groups included in Ergon Energy's network tariff structures – ICCs, CACs, SACs and EGs. For the purposes of our network pricing documents, the term 'network user' refers to both a 'customer' and an 'EG'. |
| **Power factor** | The ratio of kW to kVA at a metering point during a defined period. |
| **Premises** | Means premises owned or occupied by the customer. |
| **Public Lighting Services** | A type of Alternative Control Service. Relates to the provision, construction and maintenance of public lighting assets owned by Ergon Energy, and emerging public lighting technology. Also encompasses public lighting exit fees. |
| **Public lights – Major** | Includes the following lantern types:<br>• Metal Halide – above 125 W<br>• Mercury Vapour – above 125 W<br>• High Pressure Sodium – above 100 W. |
| **Public lights – Minor** | Includes the following lantern types:<br>• Compact Fluorescent – all wattages<br>• Fluorescent – all wattages<br>• Metal Halide – up to and including 125 W<br>• Incandescent – all wattages<br>• Low Pressure Sodium – all wattages<br>• LED – all wattages<br>• Mercury Vapour – up to and including 125 W<br>• High Pressure Sodium – up to and including 100 W. |
| **Quoted services** | A type of Alternative Control Service. Similar to fee based services, but they are priced on application as the nature and scope of these services is variable and the cost (and therefore price) is specific to the individual requestor's needs. |
| **Regulatory control period** | The regulatory control period is a five (5) year period set down by the AER. The current regulatory control period is 2015–16 to 2019–20. |
| **Regulatory year** | Is a specific financial year within a regulatory control period. |
| **Residential customer** | Means a customer who acquires electricity for domestic use (as defined in the Queensland EDNC). |
| **Revenue cap** | The TAR, as determined using the revenue cap formula set out in the Distribution Determination. |
| **Side constraint** | Refers to the percentage by which the expected weighted average revenue to be raised from a Standard Control Service tariff class is allowed to increase by between regulatory years. Side constraints are intended to set a limit (or constraint) on the level of distribution price increase to be experienced by customers from one year to the next within a regulatory control period. |

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| **Standard Asset Customer (SAC)** | Typically reflects those customers with annual energy consumption below 4 GWh p.a. Includes customers with micro-generation facilities (such as small scale PV generators) of the kind contemplated under AS 4777.1 – 2005.<br>The SAC group is further subdivided into network tariff categories based on whether:<br>• the customer's connection is metered or unmetered<br>• the customer's consumption relates to residential or business use<br>• the customer is taking supply at high voltage or low voltage<br>• the customer's consumption is above or below 100 MWh p.a.<br>• the customer has a meter installed capable of recording demand<br>• the customer's supply is capable of being controlled by Ergon Energy. |
| **SAC Large** | Those SACs that typically use between 100 MWh p.a. and 4 GWh p.a. |
| **SAC Small** | Those SACs that typically use less than 100 MWh p.a. |
| **Standard Control Service** | A distribution service provided by Ergon Energy that the AER has classified as a Standard Control Service under the NER. Includes network services, some connection services (including small customer connections) and Type 7 metering services. Ergon Energy recovers our costs in providing Standard Control Services through the DUOS component of network tariffs which are billed to retailers. |
| **Summer** | The months of December, January and February. |
| **Tariff class** | A class of customers for one or more Direct Control Services who are subject to a particular tariff or particular tariffs (as defined in the NER). |
| **Threshold demand** | The amount by which a SAC Large customer's metered monthly actual kW maximum demand is adjusted for the purposes of calculating the demand component of their network tariff.<br>The actual demand charge for any time demand tariffs and the peak and off-peak demand charges for the STOUD tariffs are applied to the kW amount by which the recorded monthly maximum demand exceeds the relevant threshold. This demand may occur at any time during the month (actual demand charge and off-peak demand charge) or during a set peak period (peak charge).<br>Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand for that month is set to zero. |
| **Time-of-Use (TOU)** | A type of network tariff where the price per kWh varies according to when the consumption occurs. The TOU tariff may apply a different price during peak and off-peak periods. |
| **Transmission Use of System (TUOS) charge** | Component of the network tariff which passes through costs associated with use of the transmission network. This includes designated pricing proposal charges as defined under the NER plus charges levied on Ergon Energy in relation to Chumvale and three Powerlink connection points. |
| **Unmetered** | A customer who takes supply where no meter is installed at the connection point. |

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| **Volume charge** | A type of charge (charging parameter) included in Ergon Energy's network tariff structures which is calculated using the customer's metered energy (kWh) consumption. It may be based on a flat rate, an inclining block or TOU charging structure (depending on the customer's applicable network tariff). |
| **West Zone** | Those areas outside the East Zone and connected to the national grid, which have a significantly higher distribution cost of supply than the East Zone. The local government areas covered by the West Zone are located in the *Information Guide for Standard Control Services*. |

## Contact information

**Manager Regulatory Determination and Pricing**
**Ergon Energy Corporation Limited**
**PO Box 264**
**FORTITUDE VALLEY QLD 4006**
**Telephone:** **13 74 66**
**Email:** netprice@ergon.com.au