



# **Ergon Energy Regulatory Proposal (revised) 2015 to 2020**

3 July 2015



## Revision history

Version	Date	Summary of changes
1.0	31 October 2014	Initial Regulatory Proposal submitted to the AER
2.0	3 July 2015	Revised Regulatory Proposal submitted to the AER

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## 1. Introduction

Ergon Energy Corporation Limited's (Ergon Energy) Regulatory Proposal sets out our regulated distribution services and the revenue and prices associated with them for the regulatory control period commencing on 1 July 2015 and ending on 30 June 2020.<sup>1</sup>

Our initial Regulatory Proposal was submitted to the Australian Energy Regulator (AER) on 31 October 2014.<sup>2</sup> The AER assessed our initial proposal and released its Preliminary Determination on 30 April 2015.

This document represents part of our submission to the AER on its Preliminary Determination.<sup>3</sup> It is referred to as our revised Regulatory Proposal.<sup>4</sup>

Our proposal, and our overview of the proposal,<sup>5</sup> complies with the requirements detailed in the National Electricity Rules (NER) and the National Electricity Law (NEL). This includes information we must provide in order for the AER to make the necessary decisions and determinations under the NER.

*Our October Regulatory Proposal has been updated in parts to reflect the positions adopted by the AER in its Preliminary Determination. Where more up-to-date information is available, we have also incorporated this in our revised Regulatory Proposal.*

*We have not made revisions in circumstances where we have concerns with the AER's decision-making, or where we disagree with the substance of the issues raised by the AER. These concerns are detailed in our main submission and its individual submission documents.*

*In preparing our revised Regulatory Proposal, Ergon Energy has also taken into account stakeholder feedback.*

### 1.1 Overview of our Regulatory Proposal

What we charge for the use of our network has fallen in 2015-16, in line with the AER's Preliminary Determination. For the remaining years of the regulatory control period 2015-20, Ergon Energy is targeting to keep what we charge for the use of our network at 2014-15 levels.

The following chart summarises the indicative movements in the aggregate network charges for the regulatory control period 2015-20, including annual increases in DUOS charges (excluding Solar Bonus Scheme feed-in tariff (FiT) costs) which represents the substance of our revised Regulatory Proposal and necessary adjustments to address the impacts of the AER's Preliminary Determination on our 2015-16 network charges.

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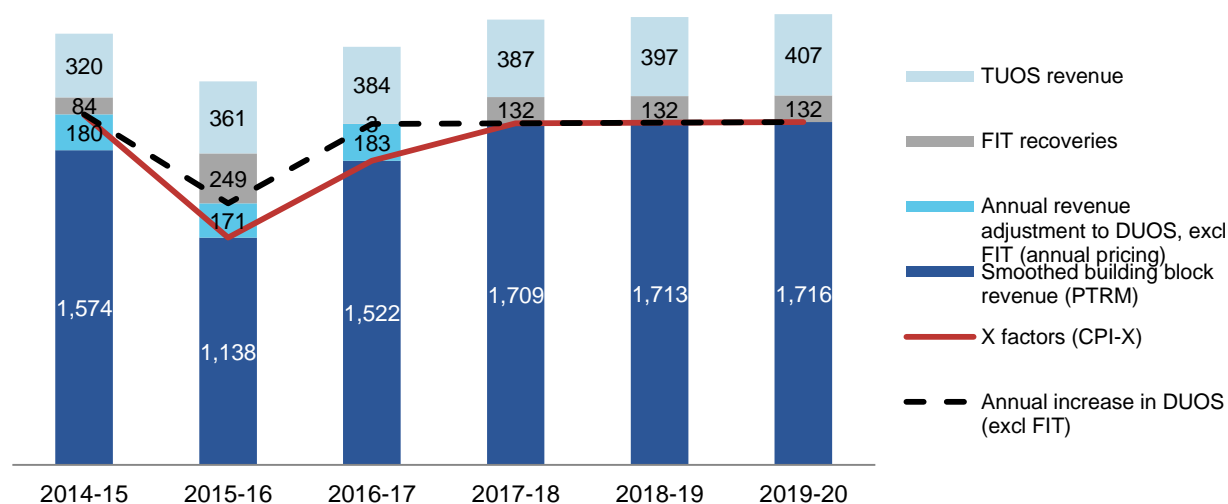
<sup>1</sup> This proposed term is consistent with the length of the regulatory control period 2010-15 and is the minimum duration for a regulatory control period permitted under clause 6.3.2(b) of the NER.

<sup>2</sup> <http://www.ergon.com.au/futureinvestment>.

<sup>3</sup> NER, clause 11.60.4(b).

<sup>4</sup> We use "Regulatory Proposal" and "revised Regulatory Proposal" interchangeably throughout this document.

<sup>5</sup> 0A.00.01 – An Overview, Our Regulatory Proposal 2015-20 and 0A.00.01 – An Overview, Our Revised Plans 2015-20.



	2015-16	2016-17	2017-18	2018-19	2019-20
- - - Annual increase in DUOS (excl FIT)	(25.4%)	30.3%	0.2%	0.2%	0.2%
- - - X Factors (CPI - X)	36.6%	(30.5%)	(9.5%)	2.3%	2.3%

Figure 1: Movement in aggregate expected network charges, 2014-20 (\$m, nominal)<sup>6</sup>

We were optimistic in October 2014 that, with improving financial markets, the costs of financing our investments would fall. This has occurred and our required revenues are now lower than we forecast in our October Regulatory Proposal. We have updated our proposal to reflect these improved financing conditions. However, we have not made the equivalent changes to the rate of return parameters the AER determined in April 2015. The AER's Preliminary Determination set these parameters too low.

Our revised capital expenditure forecasts are slightly lower, reflecting updated market expectation of cost inputs into the future. We have not adjusted these to the extent determined by the AER. The AER's Preliminary Determination contained errors (which the AER has conceded) that will need to be adjusted in the Substitute Determination.

Depreciation schedules have been revised to account for the separation of asset classes into pre and post 2009 values. This resulted in a lower depreciation allowance to what we proposed in October Regulatory Proposal; reducing the amount of revenue we recover in the regulatory control period 2015-20.

Finally, we have changed our operating expenditure forecasts. However, we cannot accept the AER's assessment process to be a reasonable one, having regard to our statutory requirements. We outline our main objections to the Preliminary Determination in our main submission, *Submission to the AER on its Preliminary Determination*, and supporting submissions.

<sup>6</sup> Revenue from Type 5 and 6 metering installation, provision, maintenance, reading and data services was previously included in DUOS in 2014-15. Since these services will be Alternative Control Services in the regulatory control period 2015-20, revenue associated with these services has not been included in DUOS for 2015-20.

There have been substantial increases in the network component of customer electricity bills in the regulatory control period 2010-15. Through our engagement program, we have a clear understanding of the level of concern about rising electricity prices. We need to adjust the AER's determined total revenue allowance because it is too low. However, setting what we charge in 2016-17 lower than what we charged in 2014-15 and targeting charges for the remaining years of the regulatory control period 2015-20 to be at or below 2014-15 levels is in line with our commitment to delivering the best possible price.

Further, in formulating our plans we have also considered our commitments around delivering peace of mind, by way of a safe, dependable electricity service, and supporting greater customer choice and control in electricity supply solutions.

Our indicative analysis of the impact of distribution charges (excluding FiT adjustments) for a typical residential customer in the regulatory control period 2015-20 is shown in Table 1 below.

**Table 1: Historic and proposed increases to our revenue requirements and associated residential price impact<sup>7</sup>**

\$ nominal	Historic annual increases in 2011-15				Annual increases in 2015-20				
	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
% change	8%	9%	11%	10%	(26%)	29%	(6%)	1%	1%
\$ change	\$53	\$69	\$91	\$90	\$ (250)	\$212	\$ (57)	\$11	\$11
Estimated impact of DUOS increase on retail bill	4%	5%	6%	5%	(12%)	16%	(3%)	1%	1%

In addition to standard charges for use of the distribution network, Ergon Energy proposes:

- new charges for Type 5 and 6 meters in line with the AER's Preliminary Determination
- reductions to public lighting charges in 2015-16, as per the AER's Preliminary Determination, with charges adjusted in 2016-17 to reflect our actual costs. For the remaining years, charges will be maintained on a price path linked to the CPI
- other user specific charges, which are consistent with our approach in the regulatory control period 2010-15.

## 1.2 Documentation

### 1.2.1 Our submission on the AER's Preliminary Determination

Our high level response to the AER's Preliminary Determination is detailed in our document, *Submission to the AER on its Preliminary Determination*. This document highlights areas where Ergon Energy agrees or disagrees with the positions adopted by the AER in its Preliminary Determination and summarises our main concerns. It also responds, at a high level, to stakeholder

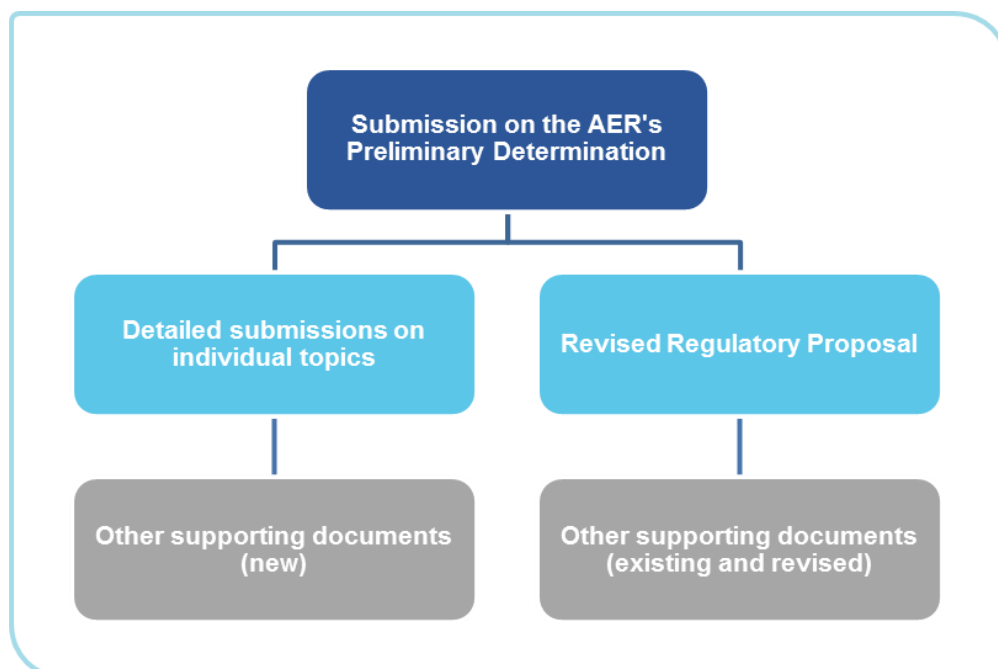
<sup>7</sup> This table is based on the Queensland Competition Authority's (QCA) assumptions of a typical residential customer in Queensland consuming 4,091 kWh per annum (held constant). Indicative prices are based on assumptions of future revenue and volumes consistent with our Regulatory Proposal. Rates are indicative for the potential impact on a residential customer who is on a market retail contract and assumes the default network tariff applies. Customers on Notified Prices are on specific arrangements consistent with the Queensland Government's Uniform Tariff Policy. For further information on how regulated retail tariffs are determined go to <http://www.dews.qld.gov.au/energy-water-home/electricity/prices>.

feedback received to date on our October Regulatory Proposal and outlines our latest customer engagement activities.

We have provided more detailed information and reasoning behind our decision to agree or disagree with the AER's Preliminary Determination in supporting documents to our submission. These documents are categorised by topic (e.g. *Rate of Return (Cost of Equity) – Response*). Revisions to our initial proposal are clearly identified in these documents. A number of other documents are also provided which support the arguments presented in the detailed submissions by topic.

Finally, we have submitted this revised Regulatory Proposal. It takes the form of the Regulatory Proposal we submitted in October 2014, but it has been updated as necessary to reflect our response to the AER's Preliminary Determination and any other updated information. Documents that accompanied our October Regulatory Proposal have also been resubmitted, either in their current form or updated to reflect new numbers and/or approaches.

A graphical depiction of the suite of information accompanying our submission to the AER is shown in Figure 2.



**Figure 2: Overall structure of our submission to the AER**

### **1.2.2 Regulatory Proposal documentation**

The information requirements for our Regulatory Proposal are extensive.<sup>8</sup> Our Regulatory Proposal therefore includes this main proposal document (including appendices), our overview and a series of supporting documents, attachments, models and reference material which provide information addressing specific regulatory issues and requirements, business as usual policies, procedures and practices, and financial and regulatory models. Each of these documents should be considered by the AER in making its Distribution Determination.

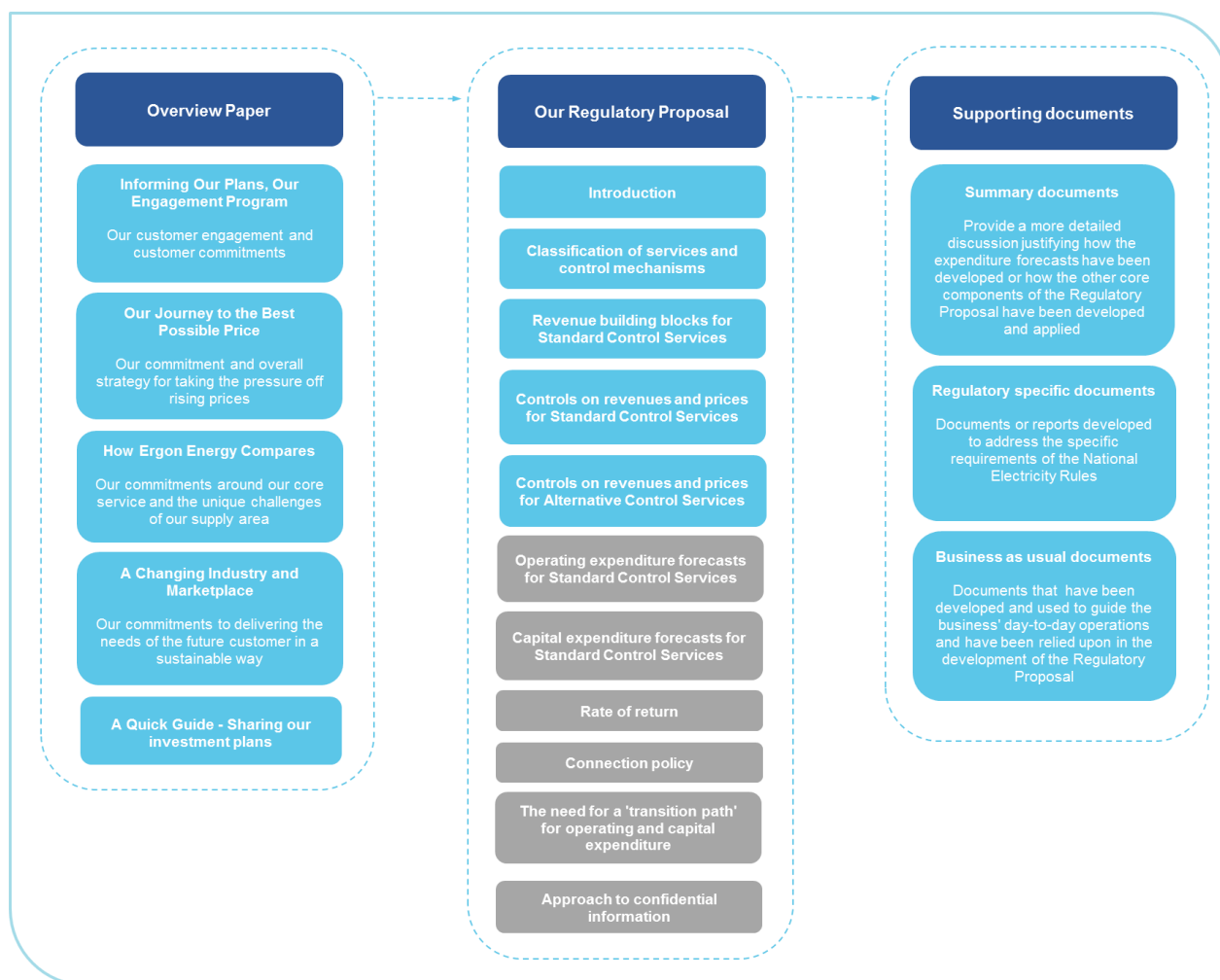
<sup>8</sup> Clause 6.8.2(c) of the NER dictates what a regulatory proposal must include. Other information is also provided to comply with the NER and to assist the AER perform its functions under the NEL.



Accompanying our Regulatory Proposal are the following documents:

- *An Overview, Our Revised Plans 2015-20*,<sup>9</sup> summarising key matters of importance to electricity customers<sup>10</sup>
- further supporting information to assist our customers understand how they have informed our plans, our response to the challenge of providing services to our customers in a changing energy market, and how we have arrived at our proposed prices
- information required by the Regulatory Information Notice (RIN) under clause 6.8.2(d) of the NER.<sup>11</sup> The RIN is used by the AER to collect information it considers necessary to assess our Regulatory Proposal. We have addressed the requirements of the RIN in this Regulatory Proposal and our supporting documents.<sup>12</sup>

A graphical depiction of the suite of information prepared with our Regulatory Proposal is provided in Figure 3.



**Figure 3: Overall structure of our Regulatory Proposal package**

<sup>9</sup> 0A.00.01 – *An Overview, Our Regulatory Proposal 2015-20* and 0A.00.01 – *An Overview, Our Revised Plans 2015-20*.

<sup>10</sup> This includes the matters required under clause 6.8.2(c1) of the NER.

<sup>11</sup> Ergon Energy assumes the AER's instrument covers the information the AER requires under clause 6.8.2(c2) of the NER, consistent with the AER's Framework and Approach Paper.

<sup>12</sup> Except for material changes, our response to the RIN has not been updated since our October Regulatory Proposal. For the avoidance of doubt, the RIN response was submitted following a formal request from the AER in August 2014. It is not required for our revised Regulatory Proposal.

## 1.3 Ergon Energy as a business

Ergon Energy is a Queensland Government-owned corporation whose principal activity is the operation of the electricity distribution system in regional Queensland. Ergon Energy holds a Distribution Authority, administered by the Director-General of the Queensland Department of Energy and Water Supply, to perform this function.

We supply electricity across a service area of more than one million square kilometres – 97% of the state of Queensland. Around 70% of the network's powerlines are considered rural, with a very low customer density and largely radial profile. We have a team of 4,415 employees who live by our values to safely deliver more than 15,000GWh of electricity annually to around 725,000 customers.

In addition to our grid-connected distribution system, the AER is responsible for the economic regulation of the Mount Isa–Cloncurry network.<sup>13</sup> Accordingly, Ergon Energy has included the Mount Isa–Cloncurry network in this Regulatory Proposal.<sup>14</sup> This is consistent with the approach adopted in the AER's Distribution Determination for the regulatory control period 2010-15.

Ergon Energy has included a supporting document, *How Ergon Energy Compares*,<sup>15</sup> which provides more information on our distribution business, customers, network and operating environment.

In addition to our core distribution business, Ergon Energy owns and operates:

- Ergon Energy Queensland Pty Ltd (EEQ), which provides electricity retail services to non-market customers in our distribution area. EEQ owns and operates the Barcaldine Power Station
- Ergon Energy Telecommunications Pty Ltd (EET), which services our communication needs and, as a licensed telecommunications carrier, offers the Queensland marketplace wholesale high-speed data services.

Ergon Energy is also a shareholder of SPARQ Solutions Pty Ltd (SPARQ), a joint venture with Energex Limited (our south-east Queensland counterpart), which provides information and communications technology (ICT) solutions and services to both organisations.

EET and EEQ's services are not regulated by the AER and are not covered in this Regulatory Proposal. However, some of SPARQ's ICT services are related to the provision of distribution services by Ergon Energy and are reflected accordingly in our Regulatory Proposal.

## 1.4 Other relevant matters

### 1.4.1 Framework and Approach

A Framework and Approach Paper is a document published before a Regulatory Proposal is submitted which sets out the AER's decisions and proposed approaches to a number of matters relevant to the Distribution Determination, such as the classification of distribution services, the forms of control to be applied and the application of incentive schemes.

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<sup>13</sup> Section 10 of the *Electricity National Scheme (Qld) 1997* treats the Mount Isa-Cloncurry supply network (which is not connected to the national grid) as a distribution system as if it were part of the national grid.

<sup>14</sup> Ergon Energy requests that the AER have regard for clause 6.8.2(e) of the NER and make a determination that Ergon Energy shall make one Regulatory Proposal that encompasses both the grid-connected network and the Mount Isa-Cloncurry network.

<sup>15</sup> Refer to *0A.01.01 – How Ergon Energy Compares*.

The AER issued the Framework and Approach Paper for Ergon Energy on 30 April 2014.<sup>16</sup> Ergon Energy took the outcomes of the AER's Framework and Approach Paper into account in preparing the October Regulatory Proposal. In its Preliminary Determination, the AER departed from the Framework and Approach Paper in some areas. To the extent we have agreed with those departures, we have updated our revised Regulatory Proposal accordingly.

### 1.4.2 Expenditure Forecast Methodology

On 29 November 2013, Ergon Energy notified the AER of the methodologies we proposed to use to forecast our capital and operating expenditure for the regulatory control period 2015-20. Our Expenditure Forecast Methodology<sup>17</sup> was developed in accordance with the NER and the AER's Expenditure Forecast Assessment Guideline. A copy of our Expenditure Forecast Methodology is available on our website.<sup>18</sup>

Our forecasts are broadly consistent with the forecasting method established in the Expenditure Forecast Methodology. We explain how Ergon Energy's Expenditure Forecast Methodology is applied to our operating and capital expenditure forecasts (including any departures from our published methodology) in Appendix A and Appendix B, respectively, and our summary documents.

### 1.4.3 Sunset of transitional arrangements for regulatory control period 2010-15

Clause 11.16 of the NER sets out the transitional arrangements for the first Distribution Determination made by the AER for the Queensland Distribution Network Service Providers (DNSPs). These transitional arrangements applied for the regulatory control period 2010-15 and cease to have effect from 1 July 2015. In addition, changes to the NER during the regulatory control period 2010-15 resulted in a number of transitional arrangements which will also cease to have effect from 1 July 2015.

The transitional arrangements related to the following matters:

- the treatment of assets included in the Regulatory Asset Base (RAB)<sup>19</sup>
- Capital Contributions Policy and treatment of capital contributions in the RAB<sup>20</sup>
- Efficiency Benefit Sharing Scheme (EBSS)<sup>21</sup>
- Service Target Performance Incentive Scheme (STPIS)<sup>22</sup>
- jurisdictional schemes<sup>23</sup>
- the recovery of charges for using the non-regulated 220 kV network which supplies the Cloncurry township<sup>24</sup>

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<sup>16</sup> Available at <http://www.aer.gov.au/node/20186>.

<sup>17</sup> As required by clause 6.8.1A of the NER.

<sup>18</sup> Refer to <https://www.ergon.com.au/network/network-management/future-investment/future-direction>.

<sup>19</sup> NER, clause 11.16.3.

<sup>20</sup> NER, clauses 11.16.10 and 11.46.6.

<sup>21</sup> NER, clause 11.16.4.

<sup>22</sup> NER, clause 11.16.5.

<sup>23</sup> NER, clause 11.35.

<sup>24</sup> NER, clause 11.39.6.

- the recovery of entry and exit charges relating to non-prescribed connection points between Powerlink’s transmission network and our distribution network.<sup>25</sup>

Further information on the cessation of these transitional arrangements and how they impact the Regulatory Proposal is contained in our supporting document *01.01.02 – (Revised) The Effect of Transitional Arrangements*.

#### **1.4.4 Transitional arrangements for regulatory control period commencing 1 July 2015**

Clause 11.60 of the NER sets out the transitional provisions that apply to Ergon Energy for the regulatory control period 2015-20. The transitional provisions effectively provide that a final Distribution Determination (the Preliminary Determination) will be made by the AER by 30 April 2015, with a revocation and substitution of the Preliminary Determination (the Substitute Determination) by 31 October 2015.<sup>26</sup>

Because the Substitute Determination is made after the commencement of the regulatory control period 2015-20, adjustments may be necessary to account for changes between the Preliminary and Substitute Determination.<sup>27</sup>

#### **1.4.5 Legislative and regulatory obligations**

Ergon Energy must comply with numerous legislative and regulatory obligations, and Queensland Government policy requirements, in the regulatory control period 2015-20. Some of these obligations directly impact our expenditure forecasts. Our supporting document *01.01.01 – (Revised) Legislative and Regulatory Obligations and Policy Requirements* provides further information on the obligations applicable to Ergon Energy.

We have also provided more detail around specific obligations relevant to:

- capital expenditure forecasts in Appendix B and in relevant supporting documentation for each capital expenditure category
- operating expenditure forecasts in Appendix A and in relevant supporting documentation
- public lighting and metering services in Chapter 5 and in relevant supporting documentation.

#### **1.4.6 Compliance with NER requirements**

The supporting evidence in our Regulatory Proposal package which demonstrates compliance with our relevant compliance obligations under Chapter 6 of the NER is detailed in our supporting document *01.02.01 – NER Compliance Matrix*. We have done this in order to assist the AER undertake its preliminary examination of the Regulatory Proposal.<sup>28</sup>

#### **1.4.7 Negotiating framework**

Neither the AER nor Ergon Energy have proposed that any services be classified as negotiated distribution services in the regulatory control period 2015-20. In its Framework and Approach

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<sup>25</sup> NER, clause 11.39.6.

<sup>26</sup> NER, clause 11.60.4(c).

<sup>27</sup> Our supporting document *04.01.00 – (Revised) Compliance with Control Mechanisms* provides some detail on how this will apply.

<sup>28</sup> NER, clause 6.9.1.

Paper, the AER decided to maintain its current position that a distributor need not submit a negotiating framework if it does not provide negotiated services.<sup>29</sup>

Since that time, the AER has revised its position and has informally requested Ergon Energy to submit a negotiating framework. We understand the AER is requesting us to provide a negotiating framework for its own compliance purposes. Our negotiating framework can be found at supporting document *01.01.03 – Ergon Energy’s Negotiating Framework*.

#### **1.4.8 Confidential information**

The information contained in this main proposal document is public information. However, some of the information in documents supporting our Regulatory Proposal is information that Ergon Energy considers to be confidential information.

Our specific confidentiality request and claims, which are made in accordance with the AER’s Confidentiality Guideline, are summarised in Appendix F.

### **1.5 Additional matters since submission of our initial proposal**

#### **1.5.1 Stakeholder consultation**

There has been considerable stakeholder consultation since the submission of our initial Regulatory Proposal on 31 October 2014. Ergon Energy has considered this feedback in developing our revised Regulatory Proposal.

#### **Issues Paper and public forum**

In December 2014, the AER released its Issues Paper on Ergon Energy’s October Regulatory Proposal.<sup>30</sup> The Issues Paper aimed to assist stakeholders by setting out the key preliminary issues on which they should engage and comment. It focused on our proposed capital and operating expenditure forecasts, and the rate of return. The AER received 31 stakeholder submissions, including a submission from Ergon Energy.<sup>31</sup>

The AER also held a public forum on 9 December 2014, which provided stakeholders and the Consumer Challenge Panel (CCP) with an opportunity to comment on the October Regulatory Proposal.

#### **Metering Consultation Paper**

In its draft decisions for New South Wales (NSW) and the Australian Capital Territory (ACT), the AER rejected the proposed metering exit fees on the basis that a large metering exit fee would create a barrier to competition. Instead, the AER proposed to recover the residual capital costs of a meter when a customer transferred to an alternative provider as a Standard Control Service.

A number of concerns were raised in response to this position. Consequently, in March 2015, the AER released a Consultation Paper on an alternative mechanism for the recovery of these costs in NSW, the ACT, Queensland and South Australia.<sup>32</sup> The AER proposed to recover these costs

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<sup>29</sup> AER (2014a), *Final Framework and approach for Energex and Ergon Energy, Regulatory control period commencing 1 July 2015*, April 2014, p154.

<sup>30</sup> AER (2014), *Issues Paper, Queensland electricity distribution regulatory proposals 2015-16 to 2019-20*, December 2014.

<sup>31</sup> See [www.aer.gov.au/node/20186](http://www.aer.gov.au/node/20186).

<sup>32</sup> AER (2015), *Alternative approach to the recovery of the residual metering capital costs through an alternative control services annual charge*, March 2015.

from both current and churned metering customers, as an annual Alternative Control Service charge.

Nineteen submissions were lodged on the Consultation Paper, including a submission from Ergon Energy.<sup>33</sup>

### Consumer Challenge Panel

The CCP sub-panel was appointed by the AER to provide advice on the effectiveness of our customer engagement and to provide input on issues of importance to customers. In addition to highlighting their initial observations at the public forum in December 2014,<sup>34</sup> the CCP sub-panel lodged two submissions in response to our October Regulatory Proposal.<sup>35</sup>

Ergon Energy also met with Hugh Grant, a CCP sub-panel member, in April 2015 to discuss our proposal in relation to the STPIS, demand management, capital expenditure, operating expenditure and the rate of return.

### Customer engagement

Since submitting our Regulatory Proposal in October 2014, Ergon Energy has continued to engage with customers and stakeholders, explaining our positions and providing additional information and reasoning where necessary. We have also engaged with customers on the outcomes of the AER's Preliminary Determination and Ergon Energy's likely response. Our submission on the AER's Preliminary Determination provides detail of our engagement arrangements.

#### 1.5.2 AER assessment process

In undertaking its assessment of our October Regulatory Proposal, the AER and its consultants met with Ergon Energy representatives and formally asked Ergon Energy almost 70 questions (with numerous sub-parts) on various aspects of our proposal. We have amended our October Regulatory Proposal to reflect the outcomes of this process, where required.

#### 1.5.3 AER Preliminary Determination for Queensland

The AER released its Preliminary Determination for Ergon Energy on 30 April 2015.<sup>36</sup> The Preliminary Determination sets out the revenue Ergon Energy is allowed to recover from customers in 2015-16 for the provision of regulated distribution services, as well as the prices that can be charged for some of these services.<sup>37</sup>

Ergon Energy has carefully reviewed the AER's Preliminary Determination. Where we agree with the positions adopted by the AER, we have made changes in this revised Regulatory Proposal.

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<sup>33</sup> [http://www.aer.gov.au/sites/default/files/Ergon%20Energy%20%282%29%20-%20Submission%20in%20response%20to%20AER%20consultation%20paper%20-%20Recovery%20of%20residual%20metering%20costs%20%20-%2027%20March%202015\\_4.pdf](http://www.aer.gov.au/sites/default/files/Ergon%20Energy%20%282%29%20-%20Submission%20in%20response%20to%20AER%20consultation%20paper%20-%20Recovery%20of%20residual%20metering%20costs%20%20-%2027%20March%202015_4.pdf).

<sup>34</sup> See [www.aer.gov.au/node/20186](http://www.aer.gov.au/node/20186).

<sup>35</sup> Bruce Mountain (2015), *CCP Sub-Panel submission on Energex, Ergon and SAPN revenues controls*; and Hugh Grant (2015), *Consumer Challenge Panel (CCP2 Panel) Submission on Energex and Ergon Energy Capex and Opex Proposals*, 30 January 2015.

<sup>36</sup> Available at <http://www.aer.gov.au/node/20186>.

<sup>37</sup> The revenues and prices to apply in 2016-17 to 2019-20 will be set out in the AER's Substitute Determination. These revenues may include any corrections for the 2015-16 year.



## 1.5.4 AER decisions in other jurisdictions

A number of regulatory determination consultation processes are occurring in other jurisdictions at the same time as our own process. In some circumstances, the issues raised in these processes are similar to our own. To assist in those processes, we have provided additional evidence by way of submissions that are also relevant to our determination process.

Ergon Energy made submissions to the AER on various determinations, including:

- the NSW and ACT electricity distribution networks
- the Jemena gas network in NSW.

On the AER's decision on rate of return, we have jointly engaged expert advice since the concerns with the AER's decision on rate of return are common across many network businesses. The expert advice is attached to our submission.

## 1.6 Supporting documentation

The following documents referenced in this chapter accompany our Regulatory Proposal:

Name	Ref	File name
An Overview, Our Revised Plans 2015-20	0A.00.01	An Overview Our Revised Plans
Regulatory Information Notice	N/A	Our response to the AER's RIN is contained in a number of files attached to this proposal. Information provided in our RIN is correct as at the time of our October Regulatory Proposal, unless otherwise stated
How Ergon Energy Compares	0A.01.01	How Ergon Energy Compares
(Revised) Legislative and Regulatory Obligations and Policy Requirements	01.01.01	(Revised) Legislative and Regulatory obligations
(Revised) The Effect of Transitional Arrangements	01.01.02	(Revised) Effect of Transitional Arrangements
Ergon Energy Negotiating Framework	01.01.03	Negotiating Framework
NER Compliance Matrix	01.02.01	Compliance checklist
(Revised) Compliance with Control Mechanisms	04.01.00	(Revised) Compliance with control mechanisms
Submission to the AER on its Preliminary Determination	N/A	Submission to the AER on its Preliminary Determination

# Chapter 2: Classification of services and control mechanisms

## Introduction and summary of changes

Ergon Energy provides a number of different services.

The AER determines how all of our regulated services are classified and how they will be regulated. This is important as it determines how prices will be set and how charges are recovered from our customers.

The main service that is incorporated within the customer's standard bill relates to the access and supply of electricity to customers. This service and a number of others are classified as Standard Control Services. However, a number of other user specific and asset specific services are separately charged. These are generally classified as Alternative Control Services.

The AER made some changes to the classification of services in its Preliminary Determination. These changes relate to metering, the undersea cable at Hayman Island and load control. We are generally comfortable with the approach taken by the AER, but we have proposed some changes to improve clarity.

## Customer benefits

Our best possible price commitment applies to our Standard Control Services. We're targeting to keep overall increases in network charges at 2014-15 levels for the four remaining years of the regulatory control period 2015-20.

This, and a number of our Alternative Control Services, is also central to our commitment to playing our part in powering economic growth by making it easier to connect to the network.

The classification changes, such as with metering services, will provide greater transparency of prices and facilitate choice. For customer-specific services, we're providing clear service definitions to ensure customers understand what services they can expect to receive.

The revised classifications will also minimise cross-subsidies – this will be complemented by more cost reflective network charges as we move forward.



## 2. Classification of services and control mechanisms

### 2.1 Background

The purpose of this chapter is to outline Ergon Energy’s proposed classification of services for the regulatory control period 2015-20 and the form of control that is proposed to apply to these services, including where Ergon Energy’s proposal may differ from that outlined by the AER in the Framework and Approach Paper and Preliminary Determination.

### 2.2 Service classification

Service classification is the process of determining which distribution services are to be subject to economic regulation under the NER and whether those services will be subject to:

- direct regulatory oversight by the AER (e.g. as a Direct Control Service subject to price or revenue setting)
- a more light-handed form of regulatory oversight (e.g. through the application of a negotiating framework)
- no regulatory oversight (e.g. where a service is unclassified).

The classification that is applied to Ergon Energy’s Direct Control Services will have a direct bearing on whether the costs of the services are recovered from:

- all customers via DUOS charges, where classified as Standard Control Services. The method by which these charges are established is discussed in Chapters 3 and 4.
- those customers requesting the service, where classified as Alternative Control Services. The method by which these charges are established is discussed in Chapter 5.

#### 2.2.1 Outcomes of the Framework and Approach Paper

The AER’s Framework and Approach Paper set out its proposed approach, including rationale, for the classification of distribution services for Ergon Energy for the regulatory control period 2015-20. The AER’s proposed classification is set out in Figure 4 below.

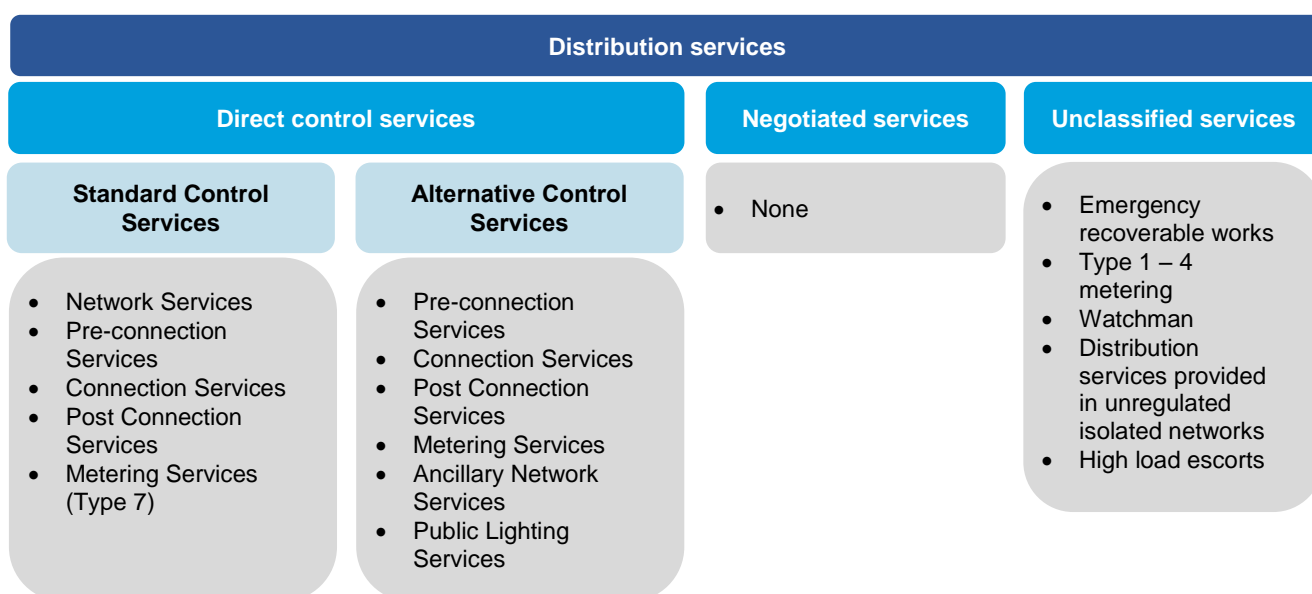


Figure 4: AER’s proposed classification of Ergon Energy’s distribution services, 2015-20

## 2.2.2 Summary of changes to last Distribution Determination

The AER's Framework and Approach Paper proposed a number of changes to the service classifications for the regulatory control period 2015-20. The proposed changes in service classifications are set out in Table 2.

**Table 2: AER's proposed changes in service classifications, 2015-20**

Service	Current classification	Proposed AER classification for 2015-20
Carrying out planning studies and analysis relating to connection applications	Standard Control / Alternative Control	Alternative Control
Feasibility and concept scoping, including planning and design, for large customer connections	Standard Control / Alternative Control	Alternative Control
Tender process	Not currently classified	Alternative Control
Protection and Power Quality assessment – prior to connection and after connection	Standard Control / Alternative Control	Alternative Control
Customer build, own and operate consultation services	Not currently classified	Alternative Control
Commissioning and energisation of large customer connections	Standard Control	Alternative Control
Real estate development connection	Standard Control	Alternative Control
Removal of network constraint for embedded generator	Standard Control	Alternative Control
Accreditation of alternative service providers and approval of their designs, works and materials	Standard Control / Alternative Control	Alternative Control
Type 5 and 6 metering installation, provision, maintenance, reading and data services	Standard Control	Alternative Control
Auxiliary metering services	Not currently classified / Standard Control / Alternative Control	Alternative Control
Services provided in relation to a Retailer of Last Resort (ROLR) event	Standard Control	Alternative Control
Customer requests provision of electricity network data requiring customised investigation, analysis or technical input	Standard Control	Alternative Control
Witness testing	Not currently classified	Alternative Control

Service	Current classification	Proposed AER classification for 2015-20
Emerging public lighting technology	Not currently classified	Alternative Control
Emergency recoverable works	Alternative Control	Unclassified
High load escorts	Alternative Control / Unclassified	Unclassified

The main implication for those services that have changed classification from a Standard Control Service to an Alternative Control Service is that the costs of providing those services will be recovered through charges levied directly on the customer requesting the service. This means that other customers are not contributing to the costs of these services.

For those services that were not previously classified, such as witness testing, Ergon Energy will be able to explicitly recover AER-approved costs of providing those services.

The change in classification for emergency recoverable works and high load escorts to “unclassified” means that the AER will have no regulatory oversight over these services in the regulatory control period 2015-20.

In addition to the above, the AER highlighted that it considers embedded generators between 30kVA and 1MW should be charged the full cost of their connection. As such, the AER has specified that these connections should be treated as large customer connections and be subject to the relevant Alternative Control Service charges.

### 2.2.3 Outcomes of the Preliminary Determination

The AER decided to apply the classification of services set out in its Framework and Approach Paper, with the following exceptions:

- The AER classified separate Type 5 and 6 metering services for:
  - meter reading and maintenance
  - meter provision before 1 July 2015
  - meter provision after 1 July 2015.
- The AER clarified that load control services provided by equipment external to a Type 5 or 6 meter is a Standard Control Service, while load control services provided by equipment internal to the meter is an Alternative Control Service.
- The undersea cable that connects Hayman Island to mainland Australia continues to be an unregulated asset. Ergon Energy proposed to include this in our RAB from 1 July 2015 in our October Regulatory Proposal.

## 2.2.4 Classification Proposal

*Our Classification Proposal adopts the AER's classification of services. However, we have proposed a number of changes to the classification of services table contained in the Preliminary Determination to improve clarity. For example, the AER has included a meter exit fee as an Auxiliary Metering Service, despite its decision to not apply such a fee in the regulatory control period 2015-20. There are also some inconsistencies regarding Type 5 and 6 metering services. We have also proposed some changes to the descriptions of some of our services.*

*Our response on these matters is contained in our submission to the AER's Preliminary Determination.*

As part of this Regulatory Proposal, Ergon Energy is required to provide a classification proposal that shows how our distribution services, in our opinion, should be classified. If our proposed classification differs from the AER's likely classification, we must include reasons for the difference.

Our classification proposal adopts the AER's classification of services set out in Attachment 15 of its Preliminary Determination, as well as the AER's decision to not classify any of our distribution services as negotiated distribution services.

Further detail on our classification proposal is contained in our supporting document *02.01.01 – (Revised) Classification Proposal*. This document also provides our interpretation of how the AER's classification of services will apply in practice in the regulatory control period 2015-20.

## 2.2.5 Unregulated services

Ergon Energy provides a range of other services (unregulated services) that do not fall within the definition of a distribution service. For example, provision of training to external parties and providing property services to customers such as conducting easement negotiations. These activities are not regulated by the AER and therefore are not subject to the Distribution Determination process.

## 2.3 Control service mechanisms

As stated in the AER's Framework and Approach Paper and Preliminary Determination, the form of control for:

- Standard Control Services will be a revenue cap.
- Alternative Control Services will be a cap on the price of individual services.

Our positions on the formulae to implement the control mechanisms, tariff design and mechanisms for adjusting the allowable revenue are set out in Chapter 4 for Standard Control Services and Chapter 5 for Alternative Control Services.

## 2.4 Supporting documentation

The following documents referenced in this chapter accompany our Regulatory Proposal:

Name	Ref	File name
(Revised) Classification Proposal	02.01.01	(Revised) Classification Proposal

# Chapter 3: Revenue building blocks for Standard Control Services

## Introduction and summary of changes

The NER details the various decisions the AER has to make in order to determine the revenue we require to recover the costs of providing Standard Control Services.

To assist the AER in making the decisions we have provided them with our 'building block' proposal. It includes all the information necessary for the AER to determine the relevant allowance for capital returns, depreciation, operating expenditure and the cost of income tax, as well as other inputs required to allow calculation of the Annual Revenue Requirement.

Our revenue requirement has been revised to reflect changes in the building block inputs such as operating expenditure, capital expenditure and the rate of return. We have also updated our depreciation schedules in response to the AER's Preliminary Determination, and updated our shared asset revenue adjustment amount to reflect 2013-14 information.

## Customer benefits

Our building block proposal is in line with our service commitment to regional Queensland, and our commitment to deliver for the best possible price.

Changes to the way we plan and operate our network, as well as the efficiencies and effectiveness we have been able to achieve as an organisation over recent years, place us in a strong position to minimise our revenue requirement.

Our customers appreciate the best possible price is not the lowest possible price. We are seeking sustainable outcomes, which address affordability concerns now without sacrificing service or affordability in the future.

## 3. Revenue building blocks for Standard Control Services

### 3.1 Background

The approach the AER must take in determining the revenue requirements for Standard Control Services is detailed in Part C of Chapter 6 of the NER.

To assist the AER undertake the task, Ergon Energy is required to develop a building block proposal, which encompasses five broad components:

- return on capital
- return of capital (depreciation)
- operating expenditure
- tax allowance
- revenue increments/decrements.

These building blocks, added together, allow the AER to determine the Annual Revenue Requirement (ARR) for each regulatory year.<sup>38</sup>

Ergon Energy's building block proposal contains the necessary information to allow the AER to make relevant decisions in accordance with the NER requirements. We have also populated the AER's Post Tax Revenue Model (PTRM) with the necessary information that allows the AER to determine the ARR, including the revenue increments and decrements set out in clause 6.4.3 of the NER.<sup>39</sup>

Ergon Energy has used a version of the PTRM developed by the AER in January 2015.<sup>40</sup> This version incorporates, among others, the following revisions:

- changes arising from the AER's Rate of Return Guideline. Specifically, an allowance for a time-varying return on debt and revenue revisions for the annual return on debt update
- explicit recognition of revenue adjustments in building block calculations
- inclusion of equity raising cost calculations in the automatic smoothing process.

This chapter summarises our approach to addressing each of the building block components, including the values we have derived for each component. It also includes information on the X-factors applied to building block revenues, as well as the application of the 2015-20 incentive schemes.

A graphical depiction of the building block approach and other components that are used in calculating the Network Use of System charge is contained in Figure 5. This diagram also shows where each component is addressed in our Regulatory Proposal.

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<sup>38</sup> NER, clause 6.4.3.

<sup>39</sup> Clause 6.4.2 of the NER requires the PTRM to set out how the ARR is to be determined. Further, clause 6.4.3 of the NER defines the building blocks that make up the ARR. We have interpreted these two clauses to mean the PTRM must include all building blocks set out in clause 6.4.3.

<sup>40</sup> Refer to *03.01.04 – Post Tax Revenue Model (January 2015)*.

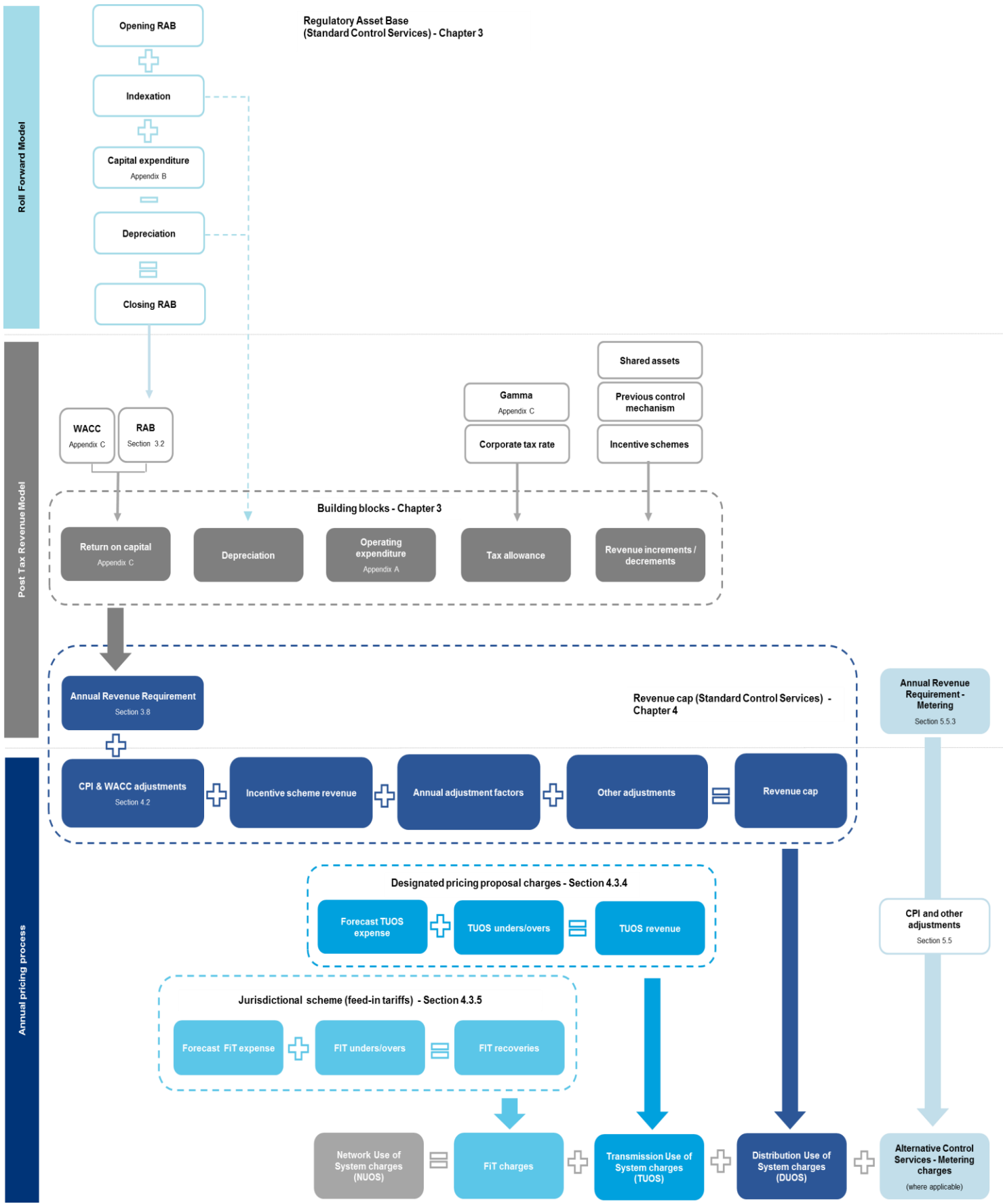


Figure 5: Components of the network bill and this Regulatory Proposal

## 3.2 Regulatory Asset Base

*The AER made a number of changes to our RAB in its Preliminary Determination. This included amendments to our opening and closing RAB values. Our submission accepts the AER's positions in relation to the removal of the Hayman Island undersea cable, equity raising costs, the removal of the movement in capitalised provisions and disposals. We have amended our October Regulatory Proposal to reflect our own updated positions on these matters, as well as latest estimates for 2014-15.*

*However, we have not updated our Regulatory Proposal to reflect the AER's Preliminary Determination on all other matters. Our submission to the AER's Preliminary Determination, SCS Building Blocks, Control Mechanism and Pricing – Response, and our supporting document provide further reasoning as to why we did not update our RAB for all elements of the AER's preliminary decision.*

When Ergon Energy spends money on an asset, for example a new substation, we are not compensated immediately for our investment. Rather, the cost Ergon Energy incurs in building that substation is usually recouped over the number of years the substation is expected to remain in service.

Ergon Energy's RAB represents the remaining value of all the capital investments we have previously made and that is still required to be recovered from customers, taking into account:

- the amount of investment already recovered from customers (through the depreciation allowance)
- the amount of investment in new assets
- any proceeds from asset disposals
- increases or decreases in the value of previous investments, because the asset is providing a different service, or the service it is providing has changed classification.

The NER sets out the arrangements for how Ergon Energy's opening RAB is to be calculated. These arrangements, as well as the AER's own Roll Forward Model (RFM) and Guidelines, dictate how Ergon Energy's prior and future investments are incorporated into prices for customers.

### 3.2.1 Establishing the RAB

Ergon Energy's opening RAB value for the commencement of the regulatory control period 2015-20 is shown in Table 3 below. This value has been derived by adjusting the value of the RAB at the beginning of the first regulatory year of the regulatory control period 2010-15 (i.e. 1 July 2010) and applying the AER's RFM.

In rolling forward the RAB, Ergon Energy has taken into account clause S6.2.1 of the NER, as well as other relevant transitional provisions.<sup>41</sup> A summary of the calculations made to derive the opening RAB as at 1 July 2015 are provided in Table 3. A more detailed explanation supporting the basis for these values is provided in supporting document *03.01.01 – (Revised) Ergon Energy's building block components (Building Blocks supporting document)*.

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<sup>41</sup> NER, clause 11.16.3.



**Table 3: Ergon Energy's Regulatory Asset Base, 2010-15**

\$m (nominal)	2010-11 Actual	2011-12 Actual	2012-13 Actual	2013-14 Actual	2014-15 Estimate
Opening RAB	7,148.95	7,843.82	8,375.96	9,034.88	9,649.23
<i>plus</i> capital expenditure (net of disposals and capital contributions)	809.48	758.18	827.97	744.00	799.60
<i>less</i> regulatory depreciation	(114.61)	(226.04)	(169.05)	(129.65)	(120.59)
<i>less</i> difference between actual and forecast net capital expenditure in 2009- 10, and the return on difference for the net capital expenditure in 2009- 10					(210.80)
<b>Closing RAB</b>	<b>7,843.82</b>	<b>8,375.96</b>	<b>9,034.88</b>	<b>9,649.23</b>	<b>10,117.43</b>
<i>less</i> adjustments to recognise changes in service classifications that occur on 1 July 2015	-	-	-	-	(61.60)
<b>Opening RAB 1 July 2015</b>					<b>10,055.83</b>

### 3.2.2 Capital Contributions

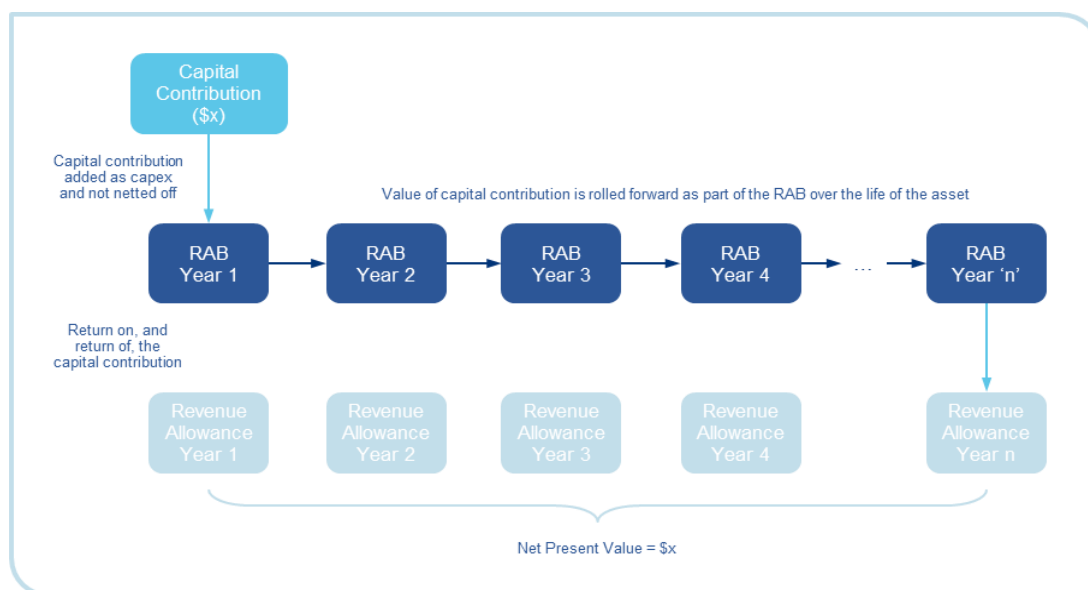
*Our analysis of the AER's models indicates that the AER has removed from our proposed PTRM all gifted and contributed assets associated with Large Customer Connections in the regulatory control period 2015-20. There is no explanation of its reasons for this and we assume this is an oversight by the AER. The inclusion of these values does not impact the value of the RAB for Standard Control Services (reflecting the prepayment, contribution of gifting). However, the omission of the values from the PTRM means that the tax allowance is understated.*

*We explain this error in more detail in our supporting submission, SCS Building Blocks, Control Mechanism and Pricing. Our revised Regulatory Proposal continues to account for these assets in the normal convention, as explained below.*

Under the transitional arrangements in clause 11.16.10 of the NER, the RAB that was used to determine the allowable revenue for the regulatory control period 2010-15 included a value for the forecast capital contributions (both cash and gifted assets). Therefore, the calculated revenue included an allowance for return of, and on, the contributed assets. To avoid Ergon Energy earning revenue from assets we did not fund, the Distribution Determination 2010-15 included a revenue adjustment, which was equal to the value of the forecast capital contributions, in the year in which the capital contribution was forecast to occur. By definition, the net present value (NPV) of the revenue stream to be earned from the capital contributions over the life of those assets is equal to the initial value of the capital contribution. A conceptual illustration of this mechanism is provided in Figure 6.

As illustrated in the diagram, the capital contributions are not removed from the RAB as doing so would result in the NPV of the revenue stream from those assets being lower than the original

value of the contributions (i.e. the original revenue adjustment would have been too high). Therefore, the value of the actual capital contributions for the regulatory control period 2010-15 have been included in the roll forward of the RAB to 1 July 2015, so that the forward revenue calculations will continue to include an amount for the return on, and of, the past capital contributions.



**Figure 6: Treatment of capital contributions under Chapter 11 of the NER**

For the regulatory control period 2015-20, forecast capital contributions related to Standard Control Services will be netted off the gross capital expenditure to determine the net capital expenditure for calculating the allowable revenue, as per the PTRM. As a result, no revenue adjustment will be required for financing and investment cost capital contributions received during the regulatory control period 2015-20.

### 3.2.3 Roll forward of the RAB

We have used the AER's PTRM to roll forward the RAB for Standard Control Services from 1 July 2015 to 30 June 2020. A summary of the roll forward values is provided in Table 4.

**Table 4: Ergon Energy's forecast Regulatory Asset Base, 2015-20**

\$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Opening RAB	10,055.83	10,674.58	11,225.76	11,750.05	12,252.24
Capital expenditure (inc. capital contributions, net of disposals)	781.03	730.34	692.33	673.32	686.22
Regulatory depreciation	(162.28)	(179.16)	(168.04)	(171.13)	(148.53)
<b>Closing RAB</b>	<b>10,674.58</b>	<b>11,225.76</b>	<b>11,750.05</b>	<b>12,252.24</b>	<b>12,789.93</b>
Inflation rate	2.55%	2.55%	2.55%	2.55%	2.55%

Further details explaining the basis for the estimates of capital expenditure for the regulatory control period 2015-20 are provided in Appendix B, and further details on the calculation of regulatory depreciation are provided later in this chapter.

### 3.2.4 Adjustments to the RAB

Ergon Energy has made adjustments for the following reasons:

- some assets were (or will be) disposed during the regulatory control period 2010-15
- some assets in the RAB used to provide services classified as Standard Control Services in the regulatory control period 2010-15 will be removed because the services that use the assets have changed classification in 2015-20.

Each of these adjustments are summarised briefly below.

#### Removal of assets due to disposals

The disposal of assets has been recognised in the roll forward of the RAB for Standard Control Services by reducing the opening asset base each year by the value of assets disposed during the regulatory year (refer to Table 3 and Table 4). This is in accordance with clause S6.2.1(e)(6) of the NER.

The value of the disposals for the regulatory control period 2010-15 is based on the actual proceeds from sale, which is consistent with the approach used for forecasting disposals in the PTRM for the regulatory control period 2015-20.

Further details explaining the basis for the actual disposals recognised in the RFM for the regulatory control period 2010-15 and the forecast disposals recognised in the PTRM for the regulatory control period 2015-20 are provided in Chapter 2 of our *Building Blocks supporting document*.

#### Removal of assets due to service reclassifications

Ergon Energy has removed Type 5 and 6 metering assets from the RAB. These assets were included in the RAB in the regulatory control period 2010-15 as they were used in the provision of Standard Control Services. However, consistent with the requirements of clause S6.2.1(e)(7) of the NER, these assets were removed from the RAB following the AER's reclassification of Type 5 and 6 metering services as Alternative Control Services for the regulatory control period 2015-20.

Further details of the reduction to the RAB to recognise the reclassification of Type 5 and 6 metering services are set out in Chapter 2 of our *Building Blocks supporting document*.

### 3.3 Return on capital

*The return on capital building block is heavily influenced by the rate of return. The AER substituted our rate of return with its own. Ergon Energy has provided reasoning as to why these changes should not be made in our submission response. For the purposes of our revised Regulatory Proposal, we have updated our allowed rate of return to reflect more up-to-date information. This includes updated market parameters, and a change to the proposed cost of debt following the AER's decision for Ergon Energy and other network service providers (NSPs).*

*Consequently, we have updated our initial return on capital values to reflect our revised rate of return.*

*Our submission, SCS Building Blocks, Control Mechanism and Pricing – Response, provides further details.*

The allowed rate of return describes the return Ergon Energy is allowed to earn on the capital invested in the regulated distribution network. According to the NER, the allowed rate of return should be such that it achieves the rate of return objective, which is:

“that the rate of return for a *Distribution Network Service Provider* is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the *Distribution Network Service Provider* in respect of the provision of *standard control services*”.<sup>42</sup>

Ergon Energy has estimated an allowed rate of return of 7.41% for the regulatory control period 2015-20, which we consider achieves the rate of return objective. A detailed explanation of how the allowed rate of return is estimated is provided in Appendix C.

The return on capital for a regulatory year is calculated as the product of the opening RAB value and the allowed rate of return. Together with the opening RAB values estimated in Table 4 above, we have estimated the return on capital for Standard Control Services for each regulatory year of the regulatory control period 2015-20, as set out in Table 5.

**Table 5: Return on capital for Standard Control Services, 2015-20**

\$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Return on capital	744.94	790.77	831.60	870.44	907.65

### 3.4 Return of capital (depreciation)

*The AER did not accept our proposed regulatory depreciation amounts for Standard Control Services. This is mainly because of changes it made to the depreciation approach. We have revised our approach to be more consistent with other NSPs and their approach to remaining lives.*

*Our PTRM and RFM reflect our revised depreciation schedules. Further details can be found in our supporting document 03.01.01 – (Revised) Ergon Energy’s Building Block Components.*

*Our submission, SCS Building Blocks, Control Mechanism and Pricing – Response, provides details and reasoning behind our decision not to reflect the AER’s substituted methodology in our revised proposal.*

As noted above, Ergon Energy recoups the cost of any investment over the life of the asset. The regulated revenue includes an allowance representing recovery of part of the RAB, based on the age profile of the assets within the RAB and the method of calculating depreciation. The AER’s PTRM requires the depreciation allowance to be offset by the indexation of the RAB (the net value is often referred to as the regulatory depreciation building block).

<sup>42</sup> NER, clause 6.5.2(c).

Our proposed regulatory depreciation for Standard Control Services for each year of the regulatory control period 2015-20 is provided in Table 6.

**Table 6: Depreciation for Standard Control Services, 2015-20**

\$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Return of capital	162.28	179.16	168.04	171.13	148.53

These forecasts have been calculated in accordance with clause 6.5.5 of the NER. Specifically, forecast depreciation has been calculated on the opening RAB value of each asset class using the straight-line depreciation methodology over the remaining life of the asset.

Our revised Regulatory Proposal updates the remaining life values for 2010 consistent with the AER’s Preliminary Determination. The AER also amended the remaining lives for each asset class in 2015, consistent with its preferred “Weighted Average Remaining Life” (WARL) methodology. However, we have not completely mirrored the AER’s preferred approach in our revised Regulatory Proposal.

We have taken into account the AER’s concerns regarding the impact that “averaging” has on depreciation schedules. In response, we sought expert advice on possible options to revise depreciation schedules and also looked to other NSP approaches. As a result we have amended our asset classes so that the remaining life of assets prior to 1 July 2009 are not averaged with capital expenditure after that date. We have adopted the WARL approach for the assets in each asset class accordingly.

A detailed explanation supporting this revised calculation of depreciation is provided in section 4.2.2 of our *Building Blocks supporting document*.

### 3.5 Operating expenditure

*The AER reduced our forecast operating expenditure by 10.5%. In reaching this position, the AER relied on a range of assessment techniques, including benchmarking. We have revised our forecast operating expenditure to reflect more recent information, including a 2013-14 base year, changes to forecast labour escalation rates and revisions to step changes.*

*Our submission in response to the AER’s Preliminary Determination and supporting submissions on operating expenditure provide further details.*

Table 7 sets out the forecast operating expenditure included in the PTRM for Standard Control Services for each year of the regulatory control period 2015-20.

These forecasts represent the requirements proposed by Ergon Energy to achieve the operating expenditure objectives outlined in clause 6.5.6(a) of the NER. A detailed explanation of the operating expenditure forecasts is included at Appendix A.

**Table 7: Proposed operating expenditure, 2015-20**

\$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Operating expenditure forecasts	354.73	377.44	399.89	418.91	439.39

### 3.6 Corporate income tax

*The AER's Preliminary Determination made adjustments to what we proposed in October 2014. Changes were made to the opening tax asset base, the remaining tax lives, gamma and other building block components.*

*We have revised our proposal to reflect the approach we have taken to remaining asset lives for regulatory depreciation. Our estimated cost of corporate income tax has also been updated in light of changes to capital expenditure, depreciation and tax asset lives.*

*We have not updated our proposal for all aspects of the AER's preliminary decision. Our submission in response to the AER's Preliminary Determination and supporting evidence provide further reasoning as to why we have not replicated all of the changes presented by the AER.*

We have estimated the cost of corporate income tax for each year of the regulatory control period 2015-20 in accordance with the requirements of the PTRM, the RFM and clause 6.5.3 of the NER. The estimated amounts for each year in the regulatory control period 2015-20 are provided in Table 8. Additional details on the approach and input variables used to calculate the cost of corporate income tax are provided in Appendix C and Chapter 6 of our *Building Blocks supporting document*.

**Table 8: Estimated cost of corporate income tax for Standard Control Services, 2015-20**

\$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Corporate income tax	96.16	119.06	126.00	132.45	127.63

### 3.7 Revenue increments/decrements

*The AER did not accept our proposed revenue adjustments for shared assets and the EBSS. For shared assets, the AER did not agree with our proposal to apply an offsetting revenue adjustment for assets that provide Alternative Control Services. Instead, the AER removed the portion of assets that provide Alternative Control Services from the RAB (i.e. no revenue adjustment). Ergon Energy does not accept the AER's preliminary decision.*

*The AER also amended our EBSS carryover reward to reflect updated information. Ergon Energy has updated our October Regulatory Proposal to reflect the AER's position on this matter.*

*Our submission in response to the AER's Preliminary Determination provides further reasoning as to why we have not replicated all of the changes presented by the AER.*

In addition to the building blocks identified in the above sections, the NER makes provision for a number of adjustments that need to be made during the regulatory control period 2015-20. Some adjustments are made directly in the calculation of the ARR as part of the building block approach (i.e. as a revenue increment or decrement). Other adjustments are made as part of the revenue cap calculation and/or in the annual Pricing Proposal (refer to Chapter 4).

This section sets out the revenue increments or decrements to the ARR, being:

- the carry forward of DUOS unders and overs from the regulatory control period 2010-15<sup>43</sup>
- two incentive schemes:<sup>44</sup>
  - EBSS
  - Demand Management Incentive Scheme (DMIS)<sup>45</sup>
- the use of shared assets.<sup>46</sup>

The revenue increments and decrements have been included in the PTRM as an individual line item within the revenue adjustment input section, consistent with the approach taken by the AER in its Preliminary Determination.

### 3.7.1 Carry forward of DUOS unders and overs

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' process is undertaken as part of annual pricing and ensures that we recover no more and no less than the Maximum Allowable Revenue<sup>47</sup> approved by the AER for any given year.

To ensure customers did not experience any unnecessary price shocks as a result of clearing any significant DUOS under or over recoveries, the AER set tolerance limits in its Distribution Determination 2010-15. Where tolerance limits were triggered, we were required to spread the under or over recovery over multiple regulatory years, instead of clearing the entire under or over recovery in setting prices for the forthcoming year.

Our 2014-15 Pricing Proposal, which was approved by the AER on 13 June 2014, highlighted that we would have a residual balance of \$53.57 million left in our DUOS unders and overs account as at 30 June 2015. We propose to clear the residual balance as a carry forward adjustment in the PTRM. Further information is contained in supporting document *03.01.02 – (Revised) Other Revenue Adjustments*.

Chapter 4 outlines how DUOS under and over recoveries from 2013-14 to 2017-18 will be dealt with in the regulatory control period 2015-20.

### 3.7.2 Incentive schemes

The EBSS seeks to provide a financial incentive for Ergon Energy to improve the efficiency of our operating expenditure and to share any resulting efficiency gains (or losses) with our customers. Any efficiency gains (or losses) are retained by Ergon Energy for five years after the gain (or loss) is realised. This means the EBSS revenue adjustment in the regulatory control period 2015-20 relates to our performance under the EBSS in the regulatory control period 2010-15.

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<sup>43</sup> NER, clause 6.4.3(a)(6) – the application of the control mechanism in the regulatory control period 2010-15.

<sup>44</sup> NER, clause 6.4.3(a)(5) – the application of incentive schemes (if any).

<sup>45</sup> NB – The NER has since changed the name of this scheme to 'Demand Management and Embedded Generation Connection Incentive Scheme' to explicitly cover innovation with respect to the connection of embedded generation. According to the Framework and Approach Paper, the AER's current and proposed DMIS includes embedded generation.

<sup>46</sup> NER, clause 6.4.3(a)(6A).

<sup>47</sup> In the regulatory control period 2015-20, due to changes to the Standard Control Services formula, the Maximum Allowable Revenue will be referred to as the Total Allowed Revenue.



Ergon Energy underspent our operating expenditure forecast in the regulatory control period 2010-15 (refer to Appendix A). This has resulted in an overall EBSS reward for Ergon Energy in the regulatory control period 2015-20 which will be passed through to customers via network charges (see Table 9). These carry-over amounts are offset by longer term efficiency gains for customers. This is because reducing operating costs results in a lower base for our forecasts in the regulatory control period 2015-20 and, ultimately, lower network prices.

The DMIS seeks to provide incentives to Ergon Energy to implement efficient non-network alternatives for managing expected demand on the network and efficiently connect embedded generators. In its Framework and Approach Paper, the AER proposed to apply Part A of the DMIS in the regulatory control period 2015-20 (i.e. the Demand Management Innovation Allowance (DMIA)). Accordingly, Ergon Energy has proposed a total DMIA allowance of \$5 million over the regulatory control period 2015-20.

Consistent with the AER’s Preliminary Determination, for revenue modelling purposes, Ergon Energy has included the \$5 million DMIA as a revenue adjustment of \$1 million per annum in 2014-15 dollars. To avoid double counting of the allowance, the DMIA has been removed from Ergon Energy’s proposed base year operating expenditure and hence is no longer included in our proposed operating expenditure for the regulatory control period 2015-20.

The following table summarises the revenue adjustments included in the building blocks for these two incentive schemes.

**Table 9: Estimated revenue adjustments associated with incentive schemes, 2015-20**

\$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
EBSS	34.61	50.42	68.83	(20.25)	0.00
DMIS (Part A, DMIA)	1.03	1.05	1.08	1.11	1.13

Further details on the incentive scheme revenue adjustments are provided in supporting document *03.01.03 – (Revised) Application of Incentive Schemes*.

### 3.7.3 Shared assets

For the regulatory control period 2010-15, we have applied clause 11.16.3 of the NER for the treatment of assets in the RAB. This has resulted in the inclusion of assets in the RAB which are used to provide Standard Control Services, Alternative Control Services and unregulated services.

To avoid double-recovery of costs, we have applied an offsetting revenue adjustment consistent with the AER’s Distribution Determination 2010-15. This ensures:

- we are not recovering revenue twice for the same assets
- customers are only paying for the costs of assets that are only used to provide Standard Control Services.

We propose to adopt this same approach in the regulatory control period 2015-20.<sup>48</sup> This means the opening RAB value at 1 July 2015 contains values for assets that are used to provide Standard

<sup>48</sup> With the exception of the true-up adjustment in the annual Pricing Proposal, which took into account the difference between the forecasts included in our revenue building blocks and our actual shared assets revenue.



Control Services, Alternative Control Services and unregulated services. Consistent with the current arrangements, we propose to apply an offsetting revenue adjustment, equivalent to the sum of the depreciation and return on assets, for the component of the shared assets that are used for purposes other than Standard Control Services.

We are of the view that this approach aligns with the principles of the shared asset mechanism outlined in the AER's Shared Asset Guideline, that customers should not pay for more than their fair share for shared assets and that service providers may propose their own cost reductions. Further, the proposed revenue adjustment is equivalent to the control, which sets a cap on the quantum of the cost reduction.

We note that the Shared Asset Guideline only contemplates the situation where assets are used to provide Standard Control Services and unregulated services. The Shared Asset Guideline does not appear to consider the situation where assets are used to provide Standard Control Services and Alternative Control Services. Given this, we propose to continue to adjust for Alternative Control Services in our revenue adjustment calculations.

Table 10 outlines our proposed revenue decrements resulting from the use of shared assets. A more detailed explanation justifying the basis of our methodology, together with the calculations used to derive the offsetting revenue adjustments, is provided in supporting document *03.01.02 – (Revised) Other Revenue Adjustments*.

**Table 10: Estimated revenue adjustment associated with the use of shared assets, 2015-20**

\$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Revenue adjustment - shared assets	(6.71)	(6.89)	(7.06)	(7.24)	(7.43)

### 3.8 Annual Revenue Requirement

*The AER determined a total revenue requirement of \$6,012.6 million over the five year period. This is 26.9% lower than our initial proposal. We do not accept the AER's decision. Our proposed ARR's have been updated to reflect changes we have made to the underlying components.*

Ergon Energy's ARR for Standard Control Services, broken down by each building block component, for the regulatory control period 2015-20 is provided in Table 11. These amounts have been calculated using the AER's PTRM, which is included as our supporting document *03.01.04 – Post Tax Revenue Model (January 2015)*.

**Table 11: Annual Revenue Requirement, 2015-20**

<b>\$m (nominal)</b>	<b>2015-16</b>	<b>2016-17</b>	<b>2017-18</b>	<b>2018-19</b>	<b>2019-20</b>
Return on capital	744.94	790.77	831.60	870.44	907.65
Return of capital	162.28	179.16	168.04	171.13	148.53
Operating expenditure	354.73	377.44	399.89	418.91	439.39
Corporate income tax	96.16	119.06	126.00	132.45	127.63
Other adjustments	87.48	44.58	62.84	(26.39)	(6.29)
Building Block Revenue (unsmoothed)	1,445.58	1,511.01	1,588.38	1,566.54	1,616.90
<b>Annual Revenue Requirement (smoothed)</b>	<b>1,137.71</b>	<b>1,522.33</b>	<b>1,709.11</b>	<b>1,712.72</b>	<b>1,716.33</b>

### 3.9 X-factors

*Ergon Energy's October Regulatory Proposal included a profile of X-factors that resulted in a smoothed revenue path (excluding FiT, but including other revenue adjustments made during the annual pricing process). The AER adopted a similar approach in its Preliminary Determination, but sought to smooth revenues inclusive of FiT. Ergon Energy does not accept the AER's approach. Rather than adopt this approach, we have maintained the same approach to establishing X factors as our October Regulatory Proposal as we believe it is more consistent with our customer commitment and less volatile to factors outside of our control.*

As noted in the PTRM Handbook, the X-factor is a price or revenue adjustment mechanism applied to the ARR to smooth the ARR over the regulatory control period and avoid price shocks between regulatory control periods.

The AER sets the X-factors consistent with the NER. This includes:

- designing the X-factors to equalise, in NPV terms, the revenue Ergon Energy can earn from the provision of Standard Control Services with the total revenue requirement for the regulatory control period
- minimising the variance between expected revenue for the last regulatory year and the ARR for that year.

This is normally achieved by making a Year 1 adjustment, and holding the smoothing adjustments in Years 2 to 5 at a constant rate (i.e. a constant 'X'). As the X-factors are only applied to revenue requirements included in the PTRM, the smoothing does not take into account other adjustments to the ARR undertaken in the annual Pricing Proposal process.

In Ergon Energy's case, the X-factors can only be adjusted for the remaining four years of the regulatory control period (2016-17 to 2019-20). This is because the prices for 2015-16 have already been established through the annual Pricing Proposal process based on the AER's Preliminary Determination.

Our revised proposal recognises the need for total allowed revenue in the remaining years to recover any smoothed ARR plus adjustments for:

- a financial reward for our performance under the STPIS
- a Solar Bonus Scheme cost pass through amount relating to FiT payments
- any DUOS under or over-recovery amount
- any under or over-recoveries relating to capital contributions and shared assets.

Consistent with our October Regulatory Proposal, we are targeting smoothed ARRs (through X-factor adjustments) that allow:

- DUOS charges (excluding Solar Bonus Scheme FiT costs) that are lower in 2016-17 than they were in 2014-15
- DUOS charges in 2019-20 being lower than what we charged customers for DUOS in 2014-15.

Ergon Energy’s proposed X-factors for Standard Control Services for each year of the regulatory control period 2015-20 are detailed in Table 12.

**Table 12: X-factors for Standard Control Services, 2015-20**

	2015-16	2016-17	2017-18	2018-19	2019-20
X-Factors	36.6%	(30.5%)	(9.5%)	2.3%	2.3%

Ergon Energy has calculated the proposed X-factors for each year of the regulatory control period 2015-20 in the PTRM, in accordance with the requirements of clause 6.5.9 of the NER. In particular, Ergon Energy has set the X-factors consistent with the NER.

### 3.10 Applying 2015-20 incentive schemes

*The AER accepted many aspects of our proposed application of each incentive scheme. However, it did not accept our incentive rates for the STPIS, our proposed exclusions from the Capital Expenditure Sharing Scheme (CESS), and the proposed carryover rewards associated with the EBSS operating in the regulatory control period 2010-15. It also decided not to apply the EBSS in 2015-20.*

*Our response on these matters is contained in our supporting submission, Incentive Schemes – Response.*

The AER’s Preliminary Determination proposed to apply the following incentive schemes to Ergon Energy in the regulatory control period 2015-20:

- DMIS
- STPIS
- CESS.

This is a departure from the Framework and Approach Paper, as the AER decided not to apply the EBSS in the regulatory control period 2015-20.

The objectives of these schemes are to provide financial incentives to DNSPs to make efficient investment decisions and to maintain and improve the efficiency of their expenditure, performance or services over time.

Ergon Energy supports the AER’s proposed approach to the application of the STPIS. However, we do not support the AER’s positions on the EBSS and the CESS. Ergon Energy believes the EBSS should apply in the regulatory control period 2015-20. If the AER determines again that the EBSS is not to apply to Ergon Energy in the regulatory control period 2015-20, the continued application of the CESS to Ergon Energy would not be appropriate. Further, we suggest that in the application of the CESS the AER should consider the potential impacts on the operation of the CESS that may be generated by Customer Connection Initiated Capital Works expenditure being above or below the expected AER allowances or forecasts for the regulatory control period 2015-20 or by decisions by a DNSP to not apply for pass throughs for events that may meet the threshold but generate capital costs that could contribute to over-expenditure of allowances. The latter concern also applies to the EBSS. Further detail is provided in our supporting document *03.01.03 – (Revised) Application of Incentive Schemes*.

It should be noted that the method and timing of the revenue adjustments associated with these incentive schemes vary, as shown in Table 13. As such, this Regulatory Proposal does not cover revenue increments or decrements associated with the CESS.

**Table 13: Adjustments associated with application of incentive schemes in 2015-20**

Incentive scheme	Method and timing of adjustment	Section
DMIS	Revenue increment in the ARR calculation in 2015-20	Section 3.7.2
STPIS	Adjustment to the AR during the annual Pricing Proposal process. There is generally a two year lag between the performance year and the pass through of the reward or penalty in prices.	Section 4.2.1
CESS	Revenue increment/decrement in the ARR calculation in 2020-25. There will be no revenue impact in 2015-20.	N/A

### 3.11 Supporting documentation

The following documents referenced in this chapter accompany our Regulatory Proposal:

Name	Ref	File name
(Revised) Ergon Energy’s Building Block Components	03.01.01	(Revised) Building Block Components
(Revised) Other Revenue Adjustments	03.01.02	(Revised) Other Revenue Adjustments
(Revised) Application of Incentive Schemes	03.01.03	(Revised) Ergon Energy Incentive Schemes
Post Tax Revenue Model (January 2015)	03.01.04	SCPTRM Data Model AER January 2015 Version
(Revised) Roll Forward Model	03.01.06	(Revised) SCRFM Data Model
SCS Building Blocks, Control Mechanism and Pricing – Response	N/A	Ergon Energy – SCS Building Blocks, Control Mechanism and Pricing – Response
Incentive Schemes – Response	N/A	Ergon Energy – Incentive Schemes – Response

# Chapter 4:

## Controls on revenue and prices for Standard Control Services

### Introduction and summary of changes

The AER places controls on the amount of revenue we are allowed to collect for our Standard Control Services through a revenue cap, consistent with the arrangements in the NER.

This chapter details Ergon Energy's proposal for how the form of control will be translated into charges for customers. These controls ultimately specify how Ergon Energy can propose prices each year, consistent with the revenue cap, taking into account adjustments allowed for matters such as inflation, incentive schemes, any under or over recoveries from previous years, or any cost pass through amounts.

Ergon Energy has generally maintained the positions set out in our October Regulatory Proposal. We have reviewed our proposed contingent projects and pass through events, and made changes as necessary. We have also proposed changes to the unders and overs accounts, which will assist us in managing any price volatility during the period.

### Customer benefits

In considering the pricing matters in this chapter we have looked to minimise price volatility where ever possible.

After reducing charges for the use of our network in 2015-16, we're targeting to keep charges overall at 2014-15 levels for the remaining four years out to 2020.

## 4. Controls on revenue and prices for Standard Control Services

### 4.1 Background

For Standard Control Services, the AER will place controls on the amount of revenue we can collect for these services (a 'revenue cap') consistent with the arrangements in the NER. This will determine the cap on revenue each year, as well as how Ergon Energy will propose prices consistent with the revenue cap, taking into account adjustments allowed for matters such as inflation, incentive schemes, any under or over recoveries from previous years, or any cost pass through amounts.

This chapter details Ergon Energy's proposal for how the form of control will be translated into charges for customers and considers a range of other pricing matters that need to be addressed as part of the Distribution Determination. These include:

- how prices and/or revenues will be controlled over the regulatory control period 2015-20,<sup>49</sup> including the form of the control mechanism<sup>50</sup> and the X-factor<sup>51</sup>
- how compliance with the control mechanism will be demonstrated<sup>52</sup>
- how customers will be assigned to tariff classes and, if required, be re-assigned between tariff classes<sup>53</sup>
- how designated pricing proposal charges (or Transmission Use of System (TUOS) charges) will be recovered, including any unders and overs adjustments<sup>54</sup>
- how Ergon Energy will report on the recovery of any jurisdictional scheme amounts, including any unders and overs adjustment for each scheme.<sup>55</sup>

Additionally, this chapter outlines other potential adjustments to the allowable revenue from factors such as contingent projects and pass through events.

### 4.2 Application of the standard control formula

*The AER has departed from the Standard Control Services formula set out in its Framework and Approach Paper. We do not support this departure, as the formula cannot be applied in practice and the AER has not justified why a departure is necessary. Our submission in response to the AER's Preliminary Determination provides further reasoning and explanation why we did not mirror the AER's decision in our revised Regulatory Proposal.*

*Ergon Energy has retained the formula contained in our October Regulatory Proposal, which was consistent with the Framework and Approach Paper. However, we have made some changes to the formula descriptions to reflect our proposed application of the formula. We have also corrected for a minor equation error.*

<sup>49</sup> NER, clause 6.2.5(a).

<sup>50</sup> NER, clause 6.12.1(11).

<sup>51</sup> NER, clause 6.12.1(12).

<sup>52</sup> NER, clause 6.12.1(13).

<sup>53</sup> NER, clause 6.12.1(17).

<sup>54</sup> NER, clause 6.12.1(19).

<sup>55</sup> NER, clause 6.12.1(20).

In line with the Framework and Approach Paper, Ergon Energy proposes that the following Standard Control Services formula should apply in the regulatory control period 2015-20:

Revenue cap (as determined by the PTRM):

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

Total allowed revenue (including adjustments):

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

$$(3) TR_t \geq \sum_{i=1}^n \sum_{j=1}^m p_{ij}^t q_{ij}^t \quad i = 1, \dots, n \text{ and } j = 1, \dots, m \text{ and } t = 1, \dots, 5$$

Where:

$AR_t$  is the allowed revenue for regulatory year t. For the first year of the regulatory control period 2015-20, this amount will be equal to the smoothed revenue requirement for 2015-16 set out in the PTRM approved by the AER. The subsequent years' allowed revenue is determined by adjusting the previous year's allowed revenue for CPI and the X-factor

$\Delta CPI_t$  is the annual percentage change in the Australian Bureau of Statistics (ABS) CPI All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1

$X_t$  is the X-factor for each year of the regulatory control period 2015-20 as determined in the PTRM, and annually revised for the return on debt update in accordance with the formula specified in the return on debt appendix I calculated for the relevant year

$TR_t$  is the total revenue allowable in year t

$I_t$  is the sum of adjustments related to:

- 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
- the STPIS. This amount will be deducted from/added to allowed revenues in regulatory year t based on the application of the S-factor

$B_t$  is the sum of adjustments related to:

- any under or over-recoveries relating to capital contributions and shared assets from 2013-14 and 2014-15
- the balance of the DUOS unders and overs account with respect to regulatory year t

$C_t$  is the sum of adjustments related to:

- feed-in tariff cost 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
- other one-off adjustments approved by the regulator in year t

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

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



## 4.2.1 Components of the revenue cap and total allowed revenue formula

The following points are made in respect of the proposed formula:

- Adjustments associated with the trailing average cost of debt will be made in the  $X_t$  component of the  $AR_t$  formula (refer to our supporting document *04.01.00 – (Revised) Compliance with Control Mechanisms*).
- Based on the previous and proposed incentive scheme arrangements,  $I_t$  will incorporate adjustments relating to:
  - STPIS. This includes rewards or penalties associated with our performance under the scheme in 2013-14 and 2014-15, which will result in adjustments in 2015-16 and 2016-17, respectively. It also encompasses rewards or penalties relating to our performance under the scheme in the first three years of the regulatory control period 2015-20, which will generally result in adjustments two years after the respective performance year.
  - DMIS. Under the current DMIS,<sup>56</sup> the AER will calculate a total carryover amount to account for any amount of allowance unspent or not approved over the regulatory control period 2010-15 and the time value of money accrued/lost as a result of the expenditure profile selected by Ergon Energy. The final carryover amount will be deducted from/added to the allowed revenue in 2016-17.
- $B_t$  will encompass:
  - any under or over-recoveries relating to capital contributions and shared assets from 2013-14 and 2014-15
  - the DUOS under and over-recovery adjustments approved to be passed through in the relevant pricing year.
- $C_t$  will include adjustments associated with:
  - FiT cost 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 (refer to Section 4.4)
  - other one-off revenue adjustments approved by the AER. This would be used in limited circumstances, and only to the extent that such adjustments are unable to be accounted for within other parameters of the revenue cap formula. For example, in the regulatory control period 2015-20, this adjustment could (if required) encompass any other true-up adjustments which may be necessary between the AER's Preliminary Determination and Substitute Determination.

Further information on our proposed treatment of the revenue cap components in the regulatory control period 2015-20 is contained in our supporting document *04.01.00 – (Revised) Compliance with Control Mechanisms*.

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<sup>56</sup> AER (2008), Demand Management Incentive Scheme, Energex, Ergon Energy and ETSA Utilities 2010-15, October 2008, p8.



## 4.3 Pricing arrangements

Clause 6.18 of the NER details the distribution pricing rules to apply to Ergon Energy's tariffs and tariff classes related to Direct Control Services in the regulatory control period 2015-20.

The following sections set out the approaches to setting tariffs that Ergon Energy intends to adopt. Ergon Energy is required to annually submit a Pricing Proposal to the AER, consistent with the requirements under clause 6.18.2 of the NER.<sup>57</sup>

### 4.3.1 Allocation of revenue to tariffs

The process for allocating and converting the total allowed revenue to network tariffs for various customers groups is described in detail in our website publication *Information Guide for Standard Control Services Pricing*.<sup>58</sup>

At a high level, the total allowed revenue is allocated to the three pricing zones (being East, West and Mount Isa) and the zonal costs are apportioned to different asset categories within each zone. The costs within the zones are then assigned to our four network user groups and converted into network tariffs that recover the costs. TUOS charges and jurisdictional scheme charges are then allocated to customers.

In accordance with clause 6.1.4 of the NER, Ergon Energy does not charge network users DUOS charges for the export of electricity generated by the user into the distribution network. However, charges for the provision of connection services may apply.

### 4.3.2 Side constraints

*The AER's Preliminary Determination sets out the side constraints formula that will apply to Ergon Energy in the regulatory control period 2015-20. Ergon Energy is generally comfortable with the approach taken by the AER. However, we have proposed some changes in our revised Regulatory Proposal to reflect the revenue cap formula set out above.*

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

Under clause 6.18.6(d) of the NER the following recovery of revenue is to be disregarded in deciding whether the permissible percentage (side constraint) has been exceeded in a particular regulatory year:

- a variation to the distribution determination as a result of cost pass through under clause 6.6 of NER
- a revocation and substitution of distribution determination for wrong information or error under clause 6.13 of NER
- pass through of designated pricing proposal charges
- pass through of jurisdictional scheme amounts for approved jurisdictional schemes

<sup>57</sup> Our 2015-16 Pricing Proposal was submitted to the AER on 21 May 2015 and was based on the outcomes of the AER's Preliminary Determination.

<sup>58</sup> Available at [www.ergon.com.au/networktariffs](http://www.ergon.com.au/networktariffs).

- any increase in the ARR as a result of changes to the allowed rate of return (effected through the application of the control mechanism formula specified in the distribution determination).

We propose to apply the following side constraints formula:

$$\frac{\left(\sum_{j=1}^m d_t^j q_t^j\right)}{\left(\sum_{j=1}^m d_{t-1}^j q_t^j\right)} \leq (1 + \Delta CPI_t)(1 - X_t)(1 + 2\%) \pm I_t \pm B_t \pm C_t$$

where each tariff class has up to 'm' components, and where:

$d_t^j$  is the proposed price for component 'j' of the tariff class for year t

$d_{t-1}^j$  is the price for component 'j' of the tariff class in year t-1

$q_t^j$  is the forecast quantity of component 'j' of the tariff class in year t

$\Delta CPI_t$  is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1

$X_t$  is the smoothing factor determined in accordance with the PTRM as approved in the AER's final decision, and annually revised for the return on debt update in accordance with the formula specified in the return on debt appendix I calculated for the relevant year. If  $X > 0$ , then X will be set equal to zero for the purposes of the side constraint formula

$I_t$  is the sum of adjustments related to:

- 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
- the STPIS. This amount will be deducted from/added to allowed revenues in regulatory year t based on the application of the S-factor

$B_t$  is the sum of adjustments related to:

- any under or over-recoveries relating to capital contributions and shared assets from 2013-14 and 2014-15
- the balance of the DUOS unders and overs account with respect to regulatory year t

$C_t$  is the sum of adjustments related to:

- feed-in tariff cost 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
- other one-off adjustments approved by the regulator in regulatory year t.

Further information is set out in our supporting document *04.01.00 – (Revised) Compliance with Control Mechanisms*.

### 4.3.3 DUOS unders and overs account

*The AER's Preliminary Determination requires Ergon Energy to maintain a DUOS unders and overs account. Ergon Energy supports this decision. However, we maintain our preference for tolerance limits to allow for the smoothing of volatility within the regulatory control period. We also now propose to include an estimate of the closing balance in year t-1 in the DUOS unders and overs account to alleviate concerns we have if tolerance limits are no longer allowed.*

Consistent with the AER's Preliminary Determination and the regulatory control period 2010-15, Ergon Energy proposes to report to the AER annually in our Pricing Proposal on the recovery of DUOS from our network tariffs, and make adjustments to subsequent pricing periods to account for over or under recovery of those charges.

Ergon Energy's preference is for tolerance limits to be applied. However, if the AER does not accept this, we propose to apply a DUOS unders and overs mechanism based on the audited closing balance in year t-2 and estimate of the closing balance in year t-1. The over or under recovery in year t-1 would be recovered via an adjustment in year t.

Further information can be found in our supporting document *04.01.00 – (Revised) Compliance with Control Mechanisms*.

### 4.3.4 Assignment of customers to tariff classes

*The AER's proposed procedures are generally consistent with those applying in the regulatory control period 2010-15. While Ergon Energy accepts many aspects of the procedures, there are a number of matters which we believe the AER should address or provide clarification on. We have summarised these concerns in our submission to the AER's Preliminary Determination. We also note the Queensland Energy and Water Ombudsman is unable to investigate assignment and reassignment objections under the Energy and Water Ombudsman Act 2006 (Qld).*

Assignment or reassignment of customers to Ergon Energy's Standard Control Service tariff classes occurs as result of:

- new connections to the network
- existing customers applying for increased capacity on the network
- a change in the customer's National Metering Identifier classification
- annual review as part of the process for developing and submitting the Pricing Proposal for approval by the AER
- requests for a review of the assigned network tariff or tariff class by either a customer and/or retailer.

Our *Information Guide for Standard Control Services Pricing*<sup>59</sup> sets out the current procedures for assigning or reassigning customers to tariff classes, as well as reviewing the basis on which a customer is charged. These procedures are consistent with the Preliminary Determination and the

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<sup>59</sup> Available at [www.ergon.com.au/networktariffs](http://www.ergon.com.au/networktariffs).

principles governing assignment or re-assignment of customers to tariff classes set out in clause 6.18.4 of the NER.

Ergon Energy proposes to apply the procedures set out in the Preliminary Determination throughout the remainder of the regulatory control period 2015-20, subject to the changes proposed in our supporting submission *SCS Building Blocks, Control Mechanism and Pricing – Response*.

#### 4.3.5 Designated pricing proposal charges

*The AER's Preliminary Determination requires Ergon Energy to maintain a TUOS unders and overs account. Ergon Energy supports this decision. However, in the event tolerance limits are not accepted for DUOS under and over recoveries, consistent with the DUOS unders and overs account, we propose to include an estimate of the closing balance in year t-1.*

*The AER also determined charges associated with Chumvale and non-prescribed Powerlink connection points should remain designated pricing proposal charges, despite the cessation of the transitional provision on 1 July 2015. We have applied the AER's decision in our revised Regulatory Proposal.*

Under clause 6.18.7 of the NER, Ergon Energy's pricing proposal must provide for tariffs designed to pass on to retail customers the designated pricing proposal charges to be incurred by us for TUOS services. The NER defines designated pricing proposal charges as any of the following:

- charges for prescribed exit services, prescribed common transmission services and prescribed TUOS services
- avoided customer TUOS charges
- charges for distribution services provided by another DNSP
- charges or payments specified in clause 11.39 of the NER.

The amount to be passed on for a particular regulatory year must not exceed the estimated amount of the TUOS charges adjusted for over and under recovery.

Clause 6.18.7(c) of the NER sets out how the over and under recovery amount must be calculated. Specifically:

- it must be consistent with the method determined in the AER's Distribution Determination
- the amount must be no more and no less than the TUOS charges Ergon Energy incurs
- it must adjust 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.

Consistent with the AER's Preliminary Determination, Ergon Energy proposes to apply a TUOS unders and overs mechanism in the regulatory control period 2015-20. That is, we will report to the AER annually in our Pricing Proposal on the recovery of TUOS from our network tariffs, and make adjustments to subsequent pricing periods to account for any under or over recovery of those charges.

Ergon Energy considers that consistency in unders and overs recovery arrangements is appropriate. On this basis, we propose to apply an unders and overs mechanism, similar to DUOS, based on the audited closing balance in year t-2 and estimate of the closing balance in year t-1. In addition to the actual under/over recovery of amounts in t-2, the estimated under or

over recovery in year t-1 would be recovered via an adjustment in year t. Our supporting document<sup>60</sup> includes details of our reporting and calculation of designated pricing proposal charges.

Ergon Energy notes a transitional definition of designated pricing proposal charges applied to Ergon Energy in the regulatory control period 2010-15.<sup>61</sup> Specifically, designated pricing proposal charges included:

- charges levied on Ergon Energy for use of the 220kV network which supplies the Cloncurry township as approved by the AER in its Distribution Determination 2010-15
- charges levied by Powerlink on Ergon Energy for entry services and exit services at the four connection points, being Queensland Nickel, Stoney Creek, King Creek and Oakey Town.<sup>62</sup>

Consistent with the AER's position in the Preliminary Determination, Ergon Energy will treat the charges levied on Ergon Energy for the use of the 220kV network that supplies the Cloncurry township and for entry and exit services at the three non-prescribed connection points as designated pricing proposal charges. These costs will therefore be reflected in TUOS charges.

#### 4.3.6 Jurisdictional schemes

*The AER did not accept our proposal to apply a two year lag to recover the amounts associated with FiT payments. The AER's Preliminary Determination recovers two amounts related to FiT recoveries in 2015-16 and 2016-17. Ergon Energy has not revised our proposal in relation to this decision. We have revised our proposal in order to adopt an overs and unders recovery arrangement consistent with what we proposed for DUOS and TUOS.*

Clause 6.18.7A of the NER states that a Pricing Proposal must provide for tariffs designed to pass on to customers a DNSP's jurisdictional scheme amounts for approved jurisdictional schemes. In Queensland, the Solar Bonus Scheme<sup>63</sup> will apply as a jurisdictional scheme in the regulatory control period 2015-20.

The amount to be passed on to customers for a particular regulatory year must not exceed the estimated amount of the jurisdictional scheme amounts for a DNSP's approved jurisdictional schemes adjusted for over or under recovery.<sup>64</sup>

Clause 6.18.7A(c) of the NER details how the over and under recovery amount must be calculated. Specifically:

- it must be consistent with the method determined in the AER's Distribution Determination, or where no such method has been determined, with the method determined by the AER in the relevant Distribution Determination in respect of TUOS charges
- the amount must be no more and no less than the jurisdictional scheme amounts Ergon Energy incurs

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<sup>60</sup> 04.01.01 – (Revised) Designated Pricing Proposal Charges.

<sup>61</sup> NER, clause 11.39.6.

<sup>62</sup> There will only be three non-prescribed connection points in the regulatory control period 2015-20.

<sup>63</sup> Pursuant to section 44A of the *Electricity Act 1994 (Qld)*.

<sup>64</sup> NER, clause 6.18.7A(b).

- it must adjust 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.

## Solar Bonus Scheme

The costs of the FiT paid under the Solar Bonus Scheme were treated as operating expenditure for the regulatory control period 2010-15, with the differences between the forecast FiT payments and actual FiT payments being a nominated pass through event. Once the cost pass through amounts are approved, Ergon Energy adjusted our annual revenue allowances to pass through these amounts to customers in our DUOS charges.

In practice, this means there is a two year lag between the year in which the payments are made, and the year in which adjustments are made to prices to fully recover amounts associated with FiT payments. For example, in our 2014-15 DUOS charges, amounts were factored in to recover the under-recovery of actual FiT payments made in the 2012-13 year.

In the regulatory control period 2015-20, these costs will be recovered as jurisdictional scheme amounts consistent with clause 6.18.7A(e)(1)(iii) of the NER.

We propose that the recovery of the costs be delayed by two years, such that the jurisdictional scheme amount for 2015-16 would be recovered in 2017-18, the jurisdictional scheme amount for 2016-17 would be recovered in 2018-19, and so on.

This approach will avoid recovery of both a FiT cost pass through amount and jurisdictional scheme amount in a single year, which would create price shocks for customers. For example, the under-recovery of actual FiT payments made in the 2013-14 year would be recovered in 2015-16 and the jurisdictional scheme amount for 2015-16 would be recovered in 2017-18, instead of both being recovered in 2015-16.

Table 14 sets out the forecast FiT payments under the Solar Bonus Scheme and the timing of the proposed recovery of the jurisdictional scheme amounts.

**Table 14: Forecast jurisdictional scheme amounts, Solar Bonus Scheme<sup>65</sup>**

\$m (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20
Forecast feed-in tariff payments	114.2	114.4	114.3	114.0	113.8
Proposed recovery of jurisdictional scheme amounts	114.2	(122.7)	131.8	132.0	131.9

In order to be consistent with the under/over recovery of TUOS amounts, if tolerance limits for DUOS under and over recoveries are not accepted, we also propose to apply an unders and overs mechanism to jurisdictional schemes, based on the audited closing balance in year t-2 and estimate of the closing balance in year t-1. In addition to the actual under/over recovery in t-2, the estimated under or over recovery in year t-1 would be recovered via an adjustment in year t.

<sup>65</sup> In order to implement Ergon Energy's two-year lag approach following the implementation of 2015-16 prices with a jurisdictional scheme component, we propose to:

- treat the recovery of jurisdictional scheme amounts through prices as an over-recovery in 2015-16
- adjust for this over-recovery when setting 2016-17 prices, by netting the 2015-16 jurisdictional scheme payments from the pass through of 2014-15 FiT payments
- recover the 2015-16 jurisdictional scheme payments through our 2017-18 prices in accordance with our proposed two-year lag.

More detailed information on the estimation of the forecast jurisdictional scheme amounts for the Solar Bonus Scheme, and how we propose to recover these amounts, is provided in our supporting document *04.01.02 – (Revised) Jurisdictional schemes*.

#### 4.4 Proposed pass through events

*The AER accepted our natural disaster and insurance cap events. However, it made some changes to the definitions proposed by Ergon Energy. We generally accept the definitional change for the natural disaster event. However, we propose the re-inclusion of 'cyclone' in the definition. We agree with the definitional change for insurance cap events. Our proposal has been amended accordingly.*

*The AER did not accept our proposed retail separation, isolated network separation or insurance events. For the latter, the AER instead introduced an insurer's credit risk event. We agree with the introduction of an insurer's credit risk event to replace the proposed insurance event. However, we disagree with the AER's position on our proposed retail separation and isolated network separation events and have therefore not made changes in our revised Regulatory Proposal.*

*Given the recent announcement to merge Ergon Energy, Energex and Powerlink, we have also proposed a new merger event.*

A cost pass through may occur within a regulatory control period when a pre-defined event occurs which materially increases or decreases a DNSP's costs to deliver Direct Control Services. In these circumstances, the AER may approve a positive (negative) pass through amount under the cost pass through provisions in the NER, effectively adjusting the approved revenue of a DNSP during a regulatory control period.

There are a number of pre-defined events set out in clause 6.6.1(a1) of the NER. In addition, the NER also provides that the Distribution Determination may specify any other event as a pass through event.

Ergon Energy proposes the following events be specified as pass through events for the regulatory control period 2015-20:

- natural disaster event
- insurance cap event
- insurer's credit risk event
- retail separation event
- isolated networks separation event
- merger event.

Ergon Energy considers these events meet the nominated pass through event considerations set out in the NER. Our proposed definitions and reasons why these events should be considered pass through events is contained in our supporting document *04.01.03 – (Revised) Nominated cost pass through events*.



## 4.5 Contingent projects

*Ergon Energy proposed one contingent project in our October Regulatory Proposal, as well as a general contingent project relating to large customer connections. The AER did not accept our proposal. We note the AER's decision and have updated our revised Regulatory Proposal accordingly. We have not identified any new contingent projects.*

Contingent projects are significant projects that are reasonably required to meet the capital expenditure objectives if a given trigger event occurs. In order to be considered a contingent project, the capital expenditure must be at least \$30 million or 5% of Ergon Energy's ARR for the first year of the regulatory control period, whichever is the larger amount.

Ergon Energy undertook an assessment process to identify potential contingent projects. This assessment:

- identified those projects in Ergon Energy's Network Capital Plan whose forecast capital expenditure exceeded the contingent project threshold
- for those projects identified above the threshold, considered whether the project:
  - has an appropriately defined trigger event
  - is reasonably required to meet the capital expenditure objectives
  - reasonably reflects the capital expenditure criteria.

Using this assessment approach, Ergon Energy did not identify any projects for consideration as a contingent project.

## 4.6 Indicative prices

*The indicative prices for selected tariffs have been updated to reflect our revised ARRs and more up-to-date information on expected annual revenue adjustments.*

The following tables set out indicative prices for selected Standard Asset Customer (SAC)<sup>66</sup> tariffs for each year of the regulatory control period 2015-20, as required under clause 6.8.2(c)(4) of the NER. These indicative prices are expressed in nominal terms.

Our response to the RIN provides indicative prices for our larger customers.<sup>67</sup>

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<sup>66</sup> Typically customers with energy consumption less than 4GWh per annum. This includes customers with micro generation facilities (such as small scale photovoltaic generators) that have similar service connection and usage profiles as other SACs without such facilities. SACs are split into two sub-groups: SAC Small (i.e. those customers who consume less than 100MWh per annum) and SAC Large (i.e. those customers who consume 100MWh or more per annum). For more information on our SAC network tariffs, refer to our *Information Guide for Standard Control Services Pricing* available at <http://www.ergon.com.au/networktariffs>.

<sup>67</sup> Refer to templates 7.6 and 7.7. Note Ergon Energy has not updated these indicative prices for the purposes of this revised Regulatory Proposal.



**Table 15: Indicative prices for SAC Small – Inclining Block Tariff (IBT) Residential – East, 2014-20**

IBT Residential (ERIB)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed (\$/day)	1.52	1.25	1.61	1.51	1.53	1.55
Volume Block 1 (\$/kWh)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Volume Block 2 (\$/kWh)	0.1531	0.0882	0.1138	0.1069	0.1082	0.1095
Volume Block 3 (\$/kWh)	0.1631	0.1182	0.1525	0.1432	0.1450	0.1467

**Table 16: Indicative prices for SAC Small – Seasonal Time-of-Use (TOU) Energy Residential – East, 2014-20**

Seasonal TOU Energy Residential (ERTO)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed (\$/day)	1.52	1.25	1.61	1.51	1.53	1.55
Volume Peak (\$/kWh)	0.5519	0.3181	0.3262	0.3345	0.3430	0.3518
Volume Shoulder (\$/kWh)	0.2666	0.3181	0.4104	0.3854	0.3902	0.3949
Volume Off Peak (\$/kWh)	0.0957	0.0506	0.0653	0.0613	0.0621	0.0628

**Table 17: Indicative prices for SAC Small – Seasonal TOU Demand Residential – East, 2014-20**

Seasonal TOU Demand Residential (ERTOUD)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed (\$/day)	n/a	0.00	0.00	0.00	0.00	0.00
Volume Peak (\$/kWh)	n/a	0.0313	0.0404	0.0379	0.0384	0.0389
Volume Off Peak (\$/kWh)	n/a	0.0313	0.0404	0.0379	0.0384	0.0389
Actual Demand Peak (\$/kWh)	n/a	64.821	66.474	68.169	69.907	71.690
Actual Demand Off Peak (\$/kWh)	n/a	12.000	15.484	14.541	14.721	14.898

**Table 18: Indicative prices for SAC Small – IBT Business – East, 2014-20**

IBT Business (EBIB)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed (\$/day)	1.52	1.25	1.61	1.51	1.53	1.55
Volume Block 1 (\$/kWh)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Volume Block 2 (\$/kWh)	0.1538	0.1085	0.1400	0.1315	0.1331	0.1347
Volume Block 3 (\$/kWh)	0.1638	0.1385	0.1787	0.1679	0.1699	0.1720

**Table 19: Indicative prices for SAC Small – Seasonal TOU Energy Business – East, 2014-20**

Seasonal TOU Energy Business (EBTOU)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed (\$/day)	1.52	1.25	1.61	1.51	1.53	1.55
Volume Peak (\$/kWh)	0.4140	0.2895	0.2968	0.3044	0.3122	0.3201
Volume Shoulder (\$/kWh)	0.3066	0.2895	0.3735	0.3507	0.3551	0.3594
Volume Off Peak (\$/kWh)	0.1236	0.0942	0.1215	0.1141	0.1156	0.1170

**Table 20: Indicative prices for SAC Small – Seasonal TOU Demand Business – East, 2014-20**

Seasonal TOU Demand Business (EBTOUD)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed (\$/day)	n/a	0.00	0.00	0.00	0.00	0.00
Volume Peak (\$/kWh)	n/a	0.0284	0.0366	0.0344	0.0348	0.0352
Volume Off Peak (\$/kWh)	n/a	0.0284	0.0366	0.0344	0.0348	0.0352
Actual Demand Peak (\$/kWh)	n/a	80.554	82.608	84.715	86.875	89.090
Actual Demand Off Peak (\$/kWh)	n/a	12.000	15.484	14.541	14.721	14.898

**Table 21: Indicative prices for SAC Large – Demand Large – East, 2014-20**

Demand Large (EDLT)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed (\$/day)	419.28	369.99	522.88	475.00	477.83	480.53
Actual Demand kW (\$/kW/month)	28.78	23.27	23.86	24.47	25.09	25.73
Volume (\$/kWh)	0.0055	0.0050	0.0071	0.0064	0.0065	0.0065

**Table 22: Indicative prices for SAC Large – Demand Medium – East, 2014-20**

Demand Medium (EDMT)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed (\$/day)	140.45	135.61	191.65	174.10	175.14	176.13
Actual Demand kW (\$/kW/month)	30.08	27.15	27.84	28.55	29.28	30.03
Volume (\$/kWh)	0.0055	0.0037	0.0053	0.0048	0.0048	0.0048

**Table 23: Indicative prices for SAC Large – Demand Small – East, 2014-20**

Demand Small (EDST)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed (\$/day)	38.73	37.96	53.65	48.73	49.02	49.30
Actual Demand kW (\$/kW/month)	33.63	32.64	33.47	34.33	35.20	36.10
Volume (\$/kWh)	0.0055	0.0042	0.0059	0.0053	0.0054	0.0054

**Table 24: Indicative prices for SAC Large – Seasonal TOU Demand – East, 2014-20**

Seasonal TOU Demand (ESTOUD)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed (\$/day)	n/a	32.00	45.22	41.08	41.33	41.56
Volume Peak (\$/kWh)	n/a	0.0000	0.0000	0.0000	0.0000	0.0000
Volume Off Peak (\$/kWh)	n/a	0.0336	0.0475	0.0432	0.0434	0.0437
Actual Demand Peak (\$/kWh)	n/a	47.83	49.05	50.30	51.58	52.90
Actual Demand Off Peak (\$/kWh)	n/a	12.94	18.28	16.61	16.71	16.80

## 4.7 Supporting documentation

The following documents referenced in this chapter accompany our Regulatory Proposal:

Name	Ref	File name
(Revised) Compliance with Control Mechanisms	04.01.00	(Revised) Compliance with control mechanisms
(Revised) Designated pricing proposal charges	04.01.01	(Revised) Designated pricing proposal charges
(Revised) Jurisdictional schemes	04.01.02	(Revised) Jurisdictional schemes
(Revised) Nominated cost pass through events	04.01.03	(Revised) Nominated pass through events
Regulatory Information Notice	N/A	Our response to the AER's RIN is contained in a number of files attached to this proposal. Information provided in our RIN is correct as at the time of our October Regulatory Proposal, unless otherwise stated.

# Chapter 5: Controls on revenue and prices for Alternative Control Services

## Introduction and summary of changes

Alternative Control Services are also subject to direct controls on revenues and price. However, the AER has more flexibility in how it calculates and controls prices compared to Standard Control Services.

Many of these services are requested by, or relate to, a specific customer, and therefore the customer directly benefiting from the service is either charged a fixed fee or a quoted price for the service. Other services relate to a particular asset or class of assets that can be distinguished from the meshed distribution network (metering and public lighting services).

We have revised our approach to Default Metering Services in light of changes proposed by the AER in its Preliminary Determination. In particular, we have proposed capital and non-capital annual metering charges. We have also introduced new fee based services to recover the costs of installing and providing Type 5 and 6 meters.

Finally, Ergon Energy has updated some of the inputs used to calculate our fee based and quoted services.

## Customer benefits

The changes to the way we plan and operate our network, as well as the efficiencies and effectiveness we have been able to achieve as an organisation over recent years, will also deliver positive price outcomes across our Alternative Control Services.

In the public lighting area, we are delivering a real decrease in prices in 2015-16, and we're making it easier to transition to new energy efficient public lighting technologies.

Transparent, cost reflective prices for Alternative Control Services will also facilitate customer choice and control.

Our revised proposal delivers lower prices for the majority of fee based and quoted services in 2015-16; both compared to our October Regulatory Proposal and the AER's Preliminary Determination. This has a flow on effect to prices in the remaining years of the regulatory control period.

## 5. Alternative Control Services

### 5.1 Background

Consistent with the Framework and Approach Paper, the AER's Preliminary Determination classified the following services as Alternative Control Services:

- Pre-connection Services
- Connection Services
- Post Connection Services
- Metering Services
- Ancillary Network Services
- Public Lighting Services.

The Preliminary Determination sets out the form of control that applies to each of these Alternative Control Services, as well as the formula that the AER proposes to use to give effect to the form of control.

This chapter sets out for each Alternative Control Service:

- the form of control to be applied
- how Ergon Energy proposes to give effect to the form of control
- how the control mechanism(s) will be applied under clause 6.8.2(c)(3) of the NER
- how compliance with the control mechanism will be demonstrated under clause 6.12.1(13) of the NER.

### 5.2 Form of control mechanism

The AER determined that it would apply a cap on the prices of individual services for all of our Alternative Control Services, which is consistent with the form of control applied in the regulatory control period 2010-15. The AER considers this approach is "more suitable than other control mechanisms for delivering cost reflective prices".<sup>68</sup>

### 5.3 Basis of the control mechanism

In its Preliminary Determination, the AER applied a limited building block approach for Default Metering Services and Public Lighting Services. For all other Alternative Control Services, the AER has applied a formula-based approach, which results in either a fixed fee or quoted price.

Ergon Energy has proposed the basis of the control mechanism which we consider should apply for each service in the following sections.

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<sup>68</sup> AER (2014a), Ibid, p67.

## 5.4 Formulae for Alternative Control Services

*Ergon Energy generally accepts the formulae proposed by the AER for Alternative Control Services. We note our revised Regulatory Proposal contains different X-factors (where applicable) to those determined by the AER. We have also made minor amendments to the formula descriptions. Our approach to classifying upfront capital charges as fee based services also means the Default Metering Services formula no longer applies to the installation and provision of Type 5 and 6 meters on or after 1 July 2015.*

*Our submissions on Alternative Control Services provide further details.*

The following sections set out the formulae to apply to Alternative Control Services. Further details on the calculation of input prices and the application of the formulae are provided in our supporting documents:

- 04.01.00 – (Revised) Compliance with Control Mechanisms
- 05.01.01 – (Revised) Public Lighting Services Summary
- 05.03.01 – (Revised) Default Metering Services Summary
- 05.05.01 – (Revised) Inputs and Assumptions for Alternative Control Services.

### 5.4.1 Quoted services

Ergon Energy proposes the following formula to determine the cost build-up of services that are priced on a 'quoted' basis:

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

Where:

Labour consists of all labour costs directly incurred in the provision of the service which may include labour on costs, fleet on costs and overheads. From 2016-17, base labour is escalated annually by  $(1 - X_i^t)(1 + \Delta CPI_t)$ . Where:

$X_i^t$  is the X-factor for service i in year t, as determined for fee based services

$\Delta CPI_t$  is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1. For example, for the 2016-17 year, t-2 is December 2014 and t-1 is December 2015 and in the 2017-18 year, t-2 is December 2015 and t-1 is December 2016 and so on.

Contractor services reflect all costs associated with the use of external labour including overheads and any direct costs incurred. The contractor services charge applies the rates under existing contractual arrangements. Direct costs incurred are passed on to the customer.

Materials reflect the cost of materials directly incurred in the provision of the service, material storage and logistics on costs and overheads.

Capital allowance represents a return on and return of capital for non-system assets.<sup>69</sup>

### 5.4.2 Fee based services

Consistent with the Preliminary Determination and our initial proposal, Ergon Energy has used the quoted services formula to establish initial prices (or base prices) for each fee based service in the first year of the regulatory control period 2015-20 (i.e. 2015-16). For the majority of services, these initial prices reflect the prices approved by the AER in our 2015-16 Pricing Proposal.<sup>70</sup>

From 2016-17, Ergon Energy proposes the following formula to give effect to the price cap for fee based services:

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

Where:

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

$p_i^t$  is the cap on the price of service 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 December in year t-2 to December in year t-1. For example, for the 2016-17 year, t-2 is December 2014 and t-1 is December 2015 and in the 2017-18 year, t-2 is December 2015 and t-1 is December 2016 and so on

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

$A_i^t$  is an adjustment factor for residual charges when customers choose to replace assets before the end of their economic life. For fee based services, the value for A is zero.

Ergon Energy considers that when setting prices for fee based services in 2016-17,  $p_i^{t-1}$  are the prices approved by the AER in the 2015-16 Pricing Proposal (where applicable).

### 5.4.3 Default Metering Services

Consistent with approach taken in the AER's Preliminary Determination, Ergon Energy has set out a schedule of prices for the first year of the regulatory control period 2015-20 for Default Metering Services (i.e. 2015-16).

From 2016-17, Ergon Energy proposes the following formula to give effect to the price cap for Default Metering Services:

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

Where:

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

$p_i^t$  is the cap on the price of service i in year t

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<sup>69</sup> Ergon Energy has included depreciation for vehicles in the fleet on-cost, which forms part of the labour cost component.

<sup>70</sup> Ergon Energy proposed different prices in our 2015-16 Pricing Proposal compared to Table 16.20 of the Preliminary Determination to reflect changes to our overhead rates and the inflation rate, and an oversight contained in the Preliminary Determination regarding the labour on-cost rate applying to the administration labour rate. The AER approved the Pricing Proposal on 12 June 2015. Our revised Regulatory Proposal contains eight new fee based services relating to the installation and provision of Type 5 and 6 meters which were not part of our 2015-16 Pricing Proposal.

$\Delta CPI_t$  is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1. For example, for the 2016-17 year, t-2 is December 2014 and t-1 is December 2015 and in the 2017-18 year, t-2 is December 2015 and t-1 is December 2016 and so on

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

$A_i^t$  is zero.

#### 5.4.4 Public Lighting Services

Consistent with approach taken in the AER's Preliminary Determination, Ergon Energy has set out a schedule of prices for the first year of the regulatory control period 2015-20 for Public Lighting Services (i.e. 2015-17).

From 2016-17, Ergon Energy proposes the following formula to give effect to the price cap for Public Lighting Services:

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

Where:

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

$p_i^t$  is the cap on the price of service 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 December in year t-2 to December in year t-1. For example, for the 2016-17 year, t-2 is December 2014 and t-1 is December 2015 and in the 2017-18 year, t-2 is December 2015 and t-1 is December 2016 and so on

$X_i^t$  is the X-factor for service i in year t. There are no X-factors for public lighting<sup>71</sup>

$A_i^t$  is an adjustment factor likely to include, but not limited to, adjustments for residual charges when customers choose to replace assets before the end of their economic life. For public lighting, the value of A is zero.

## 5.5 Default Metering Services

*Ergon Energy does not agree with the approach adopted by the AER in relation to annual metering services. Specifically, we consider that an exit fee (with accelerated depreciation) is the most equitable mechanism for recovering residual metering capital costs. Despite this, we have updated our revised Regulatory Proposal to include annual capital charges in line with the Preliminary Determination. Our proposal has also been amended to reflect our latest forecasts in relation to the underlying building blocks such as the allowed rate of return.*

*In addition, Ergon Energy is concerned that the AER has not adequately consulted with customers on the imposition of the upfront capital charge, nor has it appropriately considered the impact on customers. Ergon Energy maintains that the cost of new or upgraded meters should be included in the annual metering service charges. In the event the AER dismisses this concern, we have proposed eight new fee based services and a new quoted service in lieu of the upfront capital charges proposed by the AER.*

*Our submission, Metering – Response, provides further details.*

<sup>71</sup> X-factors may apply if the AER decides to annually update the return on debt, consistent with the approach taken for Standard Control Services.



## 5.5.1 Overview

For the first time, Ergon Energy will have separate charges for the installation, provision, maintenance, reading and data services of basic electricity meters for small to medium business and residential customers. These are the meters that measure the electricity that goes into a property, and which allow electricity retailers to bill their customers.

Ergon Energy has grouped these services based on our proposed pricing approach. Specifically, we have:

- Default Metering Services:
  - 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
  - Type 5 and 6 metering maintenance, reading and data services.
- Type 5 and 6 meter installation and provision (on or after 1 July 2015), where the new or upgraded meter is required as a result of a customer request.

For the latter, Ergon Energy will recover our costs of customer-initiated meter provision through various fixed fees. Further information on how these fees are calculated is discussed in Section 5.7.3.

The costs of Default Metering Services will be recovered via capital and non-capital charges which will be billed on a daily basis and bundled with other distribution charges to the retailer as part of the usual billing process. The daily capital and non-capital charges we are proposing for Default Metering Services in the regulatory control period 2015-20 are outlined in Table 25.

**Table 25: Daily metering charges, by service, 2015-20**

Default Metering Services \$/day (nominal)		2015-16	2016-17	2017-18	2018-19	2019-20
Primary Service	Non-capital	0.067	0.138	0.142	0.146	0.150
	Capital	0.018	0.093	0.096	0.099	0.101
Controlled load	Non-capital	0.025	0.051	0.052	0.054	0.055
	Capital	0.007	0.034	0.035	0.036	0.037
Solar	Non-capital	0.017	0.034	0.035	0.036	0.037
	Capital	0.004	0.023	0.024	0.025	0.025

Our approach to the calculation of these charges is outlined in the sections below. In summary:

- the costs of our Default Metering Services relate to specific activities set out in our Classification Proposal
- the AER has determined that the form of control will be a cap on the price of each service per annum. However, where possible, we have adopted an approach to expenditure forecasting and revenue calculation that is consistent with our approach for Standard Control Services. This includes:
  - adaptation of the same models for the calculation of the revenue requirement (i.e. PTRM and RFM)

- use of the same key input parameters for the revenue calculation including the rate of return, tax and CPI
- consistency in the approach to forecasting operating expenditure (base step trend (BST)) and application of overhead allocation in accordance with the Cost Allocation Method (CAM)
- forecasting techniques for growth and replacement in meter assets that are consistent with Standard Control Service Asset Renewal and Customer Connection Initiated Capital Works
- creating an opening asset value based on the gross replacement costs of a modern equivalent asset that has been optimised for a particular purpose and adjusted for depreciation
- applying depreciation of a newly installed meter to reflect the economic life of a meter in a competitive environment (three years) while accelerating the depreciation of sunk default metering assets to five years
- prices established based on the required revenue each year, the cost allocation weighting between primary, controlled load and solar metering services, and the forecast number of services each year.

Ergon Energy proposes that the AER account for differences between 2015-16 prices approved in its Preliminary Determination and those approved in the Substitute Determination via a 'true-up' mechanism which would adjust the prices in the remaining years of the regulatory control period 2015-20.

As Ergon Energy has taken an approach to Default Metering Services that is largely consistent with Standard Control Services, we have applied a true-up mechanism to Default Metering Services through the use of X-factors. That is, X-factors are applied in order to smooth the ARR over the regulatory control period. This is normally achieved by making a Year 1 adjustment, and holding the smoothing adjustments in Years 2 to 5 at a constant rate (i.e. a constant 'X').

In Ergon Energy's case, the X-factors can only be adjusted for the remaining four years of the regulatory control period (i.e. 2016-17 to 2019-20). This is because the prices for 2015-16 have already been established through the annual Pricing Proposal process based on the AER's Preliminary Determination. Therefore, Ergon Energy has made an adjustment in Year 2 and applied a constant X over the remaining years of the regulatory control period 2015-20. Our submission, *Metering – Response*, provides further details.

### 5.5.2 Our Default Metering Services Summary document

This section of the Regulatory Proposal provides a brief outline of the approach we have taken with Default Metering Services. Our supporting document *05.03.01 – (Revised) Default Metering Services Summary* provides important details around our approach to the calculation of required revenues and expected prices for our Default Metering Services. This includes:

- our regulatory framework
- capital expenditure requirements
- operating expenditure requirements
- calculation of required revenues

- calculation of meter tariffs and prices.

Additional materials supporting the above inputs and methodologies are also referenced in the summary document.

### 5.5.3 Nature of services

Default Metering Services are only a small part of activities that are covered by the metering services banner. In the AER's Preliminary Determination, metering services were grouped and classified in the manner set out in Table 26.<sup>72</sup>

**Table 26: Classification of metering services, 2015-20**

Service group	Description	Classification	Section in this Regulatory Proposal
Type 1 to 4 metering services	These meters record detailed energy usage and have a number of other capabilities, the most significant being remote communication facilities. These meters are mostly provided for larger users in the competitive market.	Unregulated	Not covered
Type 5 and 6 metering services	Type 5 meters record energy data in 30 minute intervals and are manually read (typically every three months). A Type 6 meter is a 'general purpose' meter that records accumulated energy consumption and is also manually read.  Ergon Energy is the only provider of Type 5 and 6 metering services in our network area. <sup>73</sup> Our service provision is regulated by Queensland-specific requirements contained in the Australian Energy Market Operator's (AEMO) Metrology Procedure. <sup>74</sup> These requirements and obligations differ to those in other jurisdictions and our costs will reflect these differences.	Alternative Control Services	This section (5.5) and Section 5.7
Type 7 metering services	Type 7 services apply where the NER specifies that a metering installation does not require a meter. Examples of such instances include street, traffic, park and community lighting meters.	Standard Control Services	Appendix A and B
Auxiliary Metering Services	These are non-routine metering services which Ergon Energy provides on request, such as Special Meter Reads.	Alternative Control Services	Section 5.7
Network Services	There are also some metering related services associated with the provision of network services to our customers (e.g. services related to load control and meter data management).	Standard Control Services	Appendix A and B

<sup>72</sup> Our supporting document *02.01.01 – (Revised) Classification Proposal* provides more detail on how different types of activities are grouped and classified in order to regulate the prices we can charge customers for our services.

<sup>73</sup> It should be noted that due to jurisdictional restrictions presently in place in Queensland, Ergon Energy does not currently provide Type 5 meters.

<sup>74</sup> AEMO (2012), *Metrology Procedure: Part A National Electricity Market*, July 2012.

#### 5.5.4 Application of the control mechanism

Our supporting document *04.01.00 – (Revised) Compliance with Control Mechanisms* notes that, to derive prices for Default Metering Services, Ergon Energy will calculate a revenue allowance using a 'limited building block' approach consistent with Part C of Chapter 6 of the NER as well as calculations set out in the AER's PTRM. Where appropriate we have also sought to apply similar approaches to forecasting, such as the use of BST modelling for operating expenditure forecasts.

The limited building block approach is used to determine allowable revenues, which is then converted into unit charges that are subject to a price cap. Ergon Energy's proposed annual Default Metering Service charges have been set based on the required revenue each year, the cost allocation weighting between primary, controlled load and solar metering services, and the forecast number of services each year.

#### 5.5.5 Building blocks for Default Metering Services

Table 27 sets out the proposed ARR for Default Metering Services for the regulatory control period 2015-20.

**Table 27: Annual Revenue Requirement for Default Metering Services, 2015-20**

\$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Return on capital	4.56	4.93	4.80	4.39	3.46
Return of capital	11.06	17.88	22.17	28.63	29.89
Operating expenditure	34.79	37.30	39.79	41.87	44.01
Corporate income tax	2.84	4.24	5.76	7.38	7.42
<b>Proposed Annual Revenue Requirement</b>	<b>53.26</b>	<b>64.35</b>	<b>72.52</b>	<b>82.27</b>	<b>84.77</b>

The proposed ARR for Default Metering Services was calculated using the PTRM, which has been provided in our supporting document *05.04.07 – (Revised) Default Metering Services PTRM*.

#### Key assumptions

The proposed ARR for Default Metering Services was based on the key inputs and assumptions, and forecasts set out in Table 28.

**Table 28: Ergon Energy's forecast Regulatory Asset Base for Default Metering Services, 2015-20**

	2015-16	2016-17	2017-18	2018-19	2019-20
<b>Meters installed</b>					
Meters (number)	1,292,638	1,323,884	1,354,734	1,385,136	1,415,059
<b>Asset Base (\$m, nominal)</b>					
Opening RAB	61.60	66.57	64.79	59.31	46.68
Capital expenditure (inc. capital contributions, net of disposals)	16.03	16.10	16.69	16.00	16.15
Regulatory depreciation	(11.06)	(17.88)	(22.17)	(28.63)	(29.89)
<b>Closing RAB</b>	<b>66.57</b>	<b>64.79</b>	<b>59.31</b>	<b>46.68</b>	<b>32.94</b>

### 5.5.6 Pricing for Default Metering Services

Ergon Energy has developed the following types of Default Metering Services charges to recover the ARR from customers:

- annual metering service charges for the primary metering service
- supplementary charges for *each* secondary controlled load
- supplementary charges for solar connections.

There are capital charges and non-capital charges under each of these categories. Capital charges recover costs associated with the provision and installation of meters prior to 1 July 2015. The non-capital charge recovers the costs of metering maintenance, meter reading and data services.

#### Indicative prices

Table 29 sets out the indicative prices for our Default Metering Services for each year of the regulatory control period 2015-20, as required under clause 6.8.2(c)(4) of the NER. These are expressed as simplified unit charges (\$ per unit).

**Table 29: Annual indicative prices for Default Metering Services, by service, 2015-20<sup>75</sup>**

Default Metering Services \$/unit (real 2014-15)		2015-16	2016-17	2017-18	2018-19	2019-20
Primary Service	Non-capital	24.44	50.27	51.74	53.27	54.86
	Capital	6.49	33.96	34.96	35.99	37.07
Controlled load	Non-capital	8.99	18.48	19.02	19.58	20.17
	Capital	2.39	12.49	12.85	13.23	13.63
Solar	Non-capital	6.08	12.50	12.86	13.25	13.64
	Capital	1.61	8.45	8.69	8.95	9.22

<sup>75</sup> These prices reflect the application of the true-up mechanism described above.

## 5.6 Public Lighting Services

*Ergon Energy generally accepts the AER's preliminary decision on Public Lighting Services. We have revised our Regulatory Proposal to reflect our latest forecast of customer numbers, as well as updates to the underlying building block components, such as the allowed rate of return.*

### 5.6.1 Overview

Ergon Energy manages an asset base of more than 150,000 public lights<sup>76</sup> that illuminate roads managed by a local government authority, or the Queensland Government's Department of Transport and Main Roads.

These lights may be:

- owned and operated by Ergon Energy (EO&O)
- gifted to Ergon Energy and thereafter maintained and operated by us (G&EO)
- customer owned and operated by someone other than Ergon Energy.

Charges to customers receiving Public Lighting Services will be in the form of a daily fixed charge. The daily charges we are proposing for Public Lighting Services in the regulatory control period 2015-20 are outlined in Table 30.

**Table 30: Daily public lighting charges, 2015-20**

Public Lighting Services \$/light/day (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20
EO&O - Major	0.9997	0.9826	0.9826	0.9826	0.9826
EO&O - Minor	0.4037	0.4570	0.4570	0.4570	0.4570
G&EO - Major	0.5956	0.5925	0.5925	0.5925	0.5925
G&EO - Minor	0.2645	0.3005	0.3005	0.3006	0.3006

Ergon Energy proposes that the AER account for differences between 2015-16 prices approved in the Preliminary Determination and those approved in the Substitute Determination via a true-up mechanism which would adjust the prices in the remaining years of the regulatory control period 2015-20. Ergon Energy has adopted this approach in setting the charges outlined in Table 30.

Our approach to the calculation of these charges is outlined in the sections below. In summary:

- the costs of our Public Lighting Services relate to activities grouped by the AER in its Framework and Approach Paper and the Preliminary Determination
- the AER has determined that the form of control will be a cap on the price of each individual service. However, where possible, we have adopted an approach to expenditure forecasting

<sup>76</sup> 'Street light' and 'public light' are used interchangeably in this Regulatory Proposal.

and revenue calculation that is consistent with our approach for Standard Control Services. This includes:

- adaptation of the same models for the calculation of the revenue requirement (i.e. PTRM and RFM)
- use of the same key input parameters for the revenue calculation including the rate of return, tax and CPI
- consistency in the approach to forecasting operating expenditure (BST) and application of overhead allocation in accordance with the CAM
- prices established based on the required revenue each year, the type of public light (Major or Minor) and ownership basis.

### 5.6.2 Our Public Lighting Services Summary document

This section of the Regulatory Proposal provides a brief outline of the approach we have taken with Public Lighting Services. Our supporting document *05.01.01 – (Revised) Public Lighting Services Summary* provides important details around our approach to the calculation of required revenues and expected prices for our Public Lighting Services. This includes:

- our regulatory framework
- capital expenditure requirements
- operating expenditure requirements
- calculation of required revenues
- calculation of proposed public lighting prices.

Additional materials supporting the above inputs and methodologies are also referenced in the summary document.

### 5.6.3 Nature of the services

If a public light is owned by Ergon Energy, the efficient costs of owning and maintaining the asset are charged to customers as a public lighting charge. Public Lighting Services include:

- the provision, construction and maintenance of public lighting assets
- emerging public lighting technology.

There are various cost components in supplying energy to a light, as summarised in Figure 7.

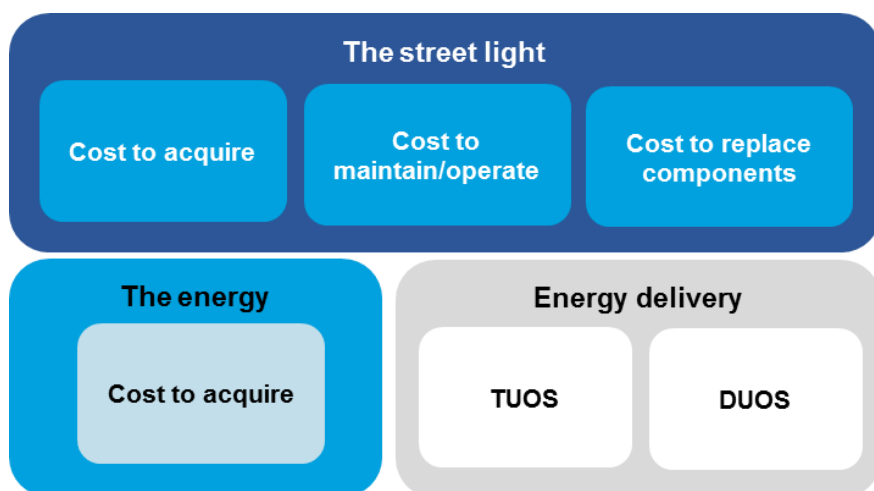


Figure 7: Cost components of public lighting

**The street light** is the equipment that directly provides the public lighting service. It includes a luminaire, lamp and a photoelectric cell or control device.

**The energy** is the electricity that powers the street light. Energy costs relate to the retailer.

**Energy delivery** consists of the services that convey electricity from the source of generation to the street light – that is, the TUOS and DUOS charges.

This section of the Regulatory Proposal focuses on the **street light** aspect only. The costs associated with this aspect are recovered as Alternative Control Service charges.

Our proposal on public lighting charges comes at a time of transition for the users of our public lighting services. Up until 1 July 2014, all public lighting Alternative Control Service charges<sup>77</sup> were borne by the Queensland Government as part of the Community Service Obligation. From that date, 10% of the current Alternative Control Service charge has been borne by customers. The Queensland Government has announced its intention that all costs will be recovered from customers in future – giving consideration to customer needs. The timetable for this is not known.

In response we have undertaken significant engagement on this area of our service over the last 12-18 months, resulting in our identification of three clear imperatives for delivery to customers:

- the ongoing importance of public lighting to the safety of the public as motorists and pedestrians
- the completion of the state-wide audit and the associated development of the LightMap software will provide Ergon Energy and our public lighting customers with a system framework for efficiently managing public lighting assets
- recognition and evaluation of the capacity for light emitting diode (LED) based technology to reduce public lighting costs in a number of ways. LED technology has improved rapidly over the past five years to the point it is starting to be used in mass deployment programs. In the local context, a number of technical, regulatory and financial barriers need to be worked through.

<sup>77</sup> With the exception of removal/relocation of Ergon Energy owned public lighting assets.



## 5.6.4 Application of the control mechanism

Our supporting document *04.01.00 – (Revised) Compliance with Control Mechanisms* notes that Ergon Energy will calculate a revenue allowance using approaches consistent with Part C of Chapter 6 of the NER as well as calculations set out in the AER's PTRM. Where appropriate we have also sought to apply similar approaches to forecasting, such as the use of BST modelling for operating expenditure forecasts.

The limited building block approach is used to determine allowable revenues, which is then converted into unit charges that are subject to a price cap.

## 5.6.5 Building blocks for Public Lighting Services

Table 31 sets out the proposed ARR for Public Lighting Services for the regulatory control period 2015-20.

**Table 31: Annual Revenue Requirement for Public Lighting Services, 2015-20**

\$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Return on capital	5.75	6.26	6.60	7.00	7.41
Return of capital	4.87	6.68	6.06	6.73	7.45
Operating expenditure	12.50	13.35	14.18	14.87	15.60
Corporate income tax	4.31	4.45	4.51	4.50	4.48
<b>Proposed Annual Revenue Requirement</b>	<b>27.43</b>	<b>30.74</b>	<b>31.35</b>	<b>33.10</b>	<b>34.94</b>

The proposed ARR for Public Lighting Services was calculated using the PTRM, which has been provided in our supporting document *05.02.03 – (Revised) Public Lighting Services PTRM*.

### Key assumptions

The proposed ARR for Public Lighting Services was based on the key assumptions and forecast set out in Table 32.

**Table 32: Assumptions supporting the revenue calculations for Public Lighting Services, 2015-20**

	2015-16	2016-17	2017-18	2018-19	2019-20
<b>Connections</b>					
<i>Public Lighting (number)</i>					
Ergon Energy owned & operated	90,733	91,416	92,098	92,780	93,463
Gifted & Ergon Energy operated	52,335	53,985	55,635	57,285	58,935
Growth (% per annum)	1.70%	1.60%	1.60%	1.60%	1.60%
<b>Asset Base (\$m, nominal)</b>					
Opening RAB	77.57	84.50	89.10	94.53	100.05

	2015-16	2016-17	2017-18	2018-19	2019-20
Capital expenditure (inc. capital contributions, net of disposals)	11.80	11.29	11.49	12.25	13.44
Regulatory depreciation	(4.87)	(6.68)	(6.06)	(6.73)	(7.45)
<b>Closing RAB</b>	<b>84.50</b>	<b>89.10</b>	<b>94.53</b>	<b>100.05</b>	<b>106.04</b>

## LED Transition

Public lighting customers are increasingly requesting the introduction of more efficient lighting technologies, particularly LED technology. Ergon Energy considers that, based on international evidence and our own involvement in LED trials, the future technology for public lighting is almost certainly going to be LED. To enable a transitional pathway to this future for our customers, Ergon Energy proposes the following approach:

- progressing regulatory, technical and customer engagement to allow LED to be introduced for new public lighting installations
- specific provision for the conversion of targeted existing public lighting to LED technology with the sunk cost of assets replaced spread across all public lighting customers through the daily charge
- flexibility for customers to adopt LED technology above and beyond the funded LED conversion program.

### 5.6.6 Pricing for Public Lighting Services

For the regulatory control period 2010-15, the AER approved a standard price for both lights owned by Ergon Energy and those gifted to Ergon Energy by or on behalf of customers. The only pricing distinction made during the regulatory control period 2010-15 was between major and minor public lights.

With customers now bearing a portion of the Alternative Control Service charge and the intention that they will bear all of the cost, Ergon Energy recognises the obligation to propose different prices where there is a material variation in the cost.

For the regulatory control period 2015-20, Ergon Energy proposes a price structure as follows:

- EO&O
  - Major
  - Minor
- G&EO
  - Major
  - Minor.

## Exit fee

In support of the LED transition program, Ergon Energy proposes to establish an exit fee payable when public lights are scrapped before the end of their useful operational life.

If public lights are transitioned under the LED transition program the exit fee will be funded through the allowance made in the revenue requirement. If a public lighting customer seeks to convert a large number of public lights outside of the LED transition program, the customer will be required to pay the exit fee.

The proposed fees in 2015-16 are set out in Table 33.

**Table 33: Exit fees, 2015-16 (\$ nominal)**

Public lighting category	Exit fee
EO&O - Major	\$1,390
EO&O - Minor	\$840
G&EO - Major	\$230
G&EO - Minor	\$195

Note: an exit fee is proposed for G&EO lights because Ergon Energy incurs refurbishment capital expenditure in respect of these assets.

## 5.7 Fee based and quoted services

*Ergon Energy generally accepts the AER's preliminary decision on fee based and quoted services. However, we seek clarification on a number of matters.*

*Our revised Regulatory Proposal has been updated to reflect prices approved by the AER in our 2015-16 Pricing Proposal and changes to underlying inputs (such as inflation and escalators) in later years. We have also introduced new fee based services relating to the installation and provision of Type 5 and 6 meters.*

*Our submission, Alternative Control Services (Other) – Response, provides further detail on these changes.*

### 5.7.1 Nature of the services

Table 34 sets out the other services which we are proposing should be classified as Alternative Control Services in the regulatory control period 2015-20 and the specific services within each grouping.<sup>78</sup>

**Table 34: Fee based and quoted services, 2015-20**

Service grouping	Services	Service description
Pre-connection Services	Connection application services	Services associated with assessing a connection application, making a connection offer and negotiating offer acceptance
	Pre-connection consultation services	Additional support services provided by Ergon Energy (on request) during connection enquiry and connection application (other than General Connection Enquiry Services and Connection Application Services). They generally relate to services which require a customised or site-specific response and/or are available contestably

<sup>78</sup> For further information on the individual services refer to 02.01.01 – (Revised) Classification Proposal.

Service grouping	Services	Service description
Connection Services	Major customer connections	Design and construction of connection assets for major customers
	Commissioning and energisation of major customer connections	Commissioning and energisation of major customer connection assets to allow conveyance of electricity, and the inspection and testing of connection assets
	Real estate development connection	Design, construction, commissioning and energisation of connection assets for real estate developments
	Removal of network constraint for embedded generator	Augmenting the network to remove a constraint faced by an embedded generator
	Temporary connections	Relates to situations where a customer requests a temporary connection for short term supply (e.g. blood bank vans, school fetes etc.)
Post Connection Services	Connection management services (post connection)	Work initiated by a customer which is specific to a connection point
	Accreditation of alternative service providers and approval of their designs, works and materials	As per service
Metering Services	Auxiliary Metering Services	Non-routine metering services such as additions and alterations, special meter reads, meter reconfiguring, meter inspection and investigation, and other non-standard metering services
	Type 5 and 6 meter installation and provision (on or after 1 July 2015), where the new or upgraded meter is required as a result of a customer request	On site connection of a new Type 5 or 6 meter at a customer's premises, and on site connection of an upgraded Type 5 or 6 meter at a customer's premises where the customer initiates the upgrade
Ancillary Network Services	Services provided in relation to a Retailer of Last Resort (ROLR) event	As per service
	Other recoverable works	Works initiated by a customer that are not covered by another service and are not required for the efficient management of the network, or to satisfy distributor purposes or obligations
Public Lighting Services	Provision, construction and maintenance of public lighting	Removal/rearrangement of public lighting assets.

### 5.7.2 Application of the control mechanism

The AER has proposed to set prices based on the estimated cost of providing each service.

For some services, prices will be determined on a quoted basis (i.e. 'quoted services'). This means the prices are based on several types and quantities of inputs which vary depending on the service requested. Prices for other services will be charged on a fixed fee basis (i.e. 'fee based services').

The first step in determining prices is to identify which services will be priced on a quoted basis versus a fixed fee basis. Table 35 provides a summary of our proposed pricing approach for each service grouping.

**Table 35: Proposed approach to pricing of other Alternative Control Services, 2015-20**

Service grouping	Services	Pricing approach
Pre-connection Services	Connection application services	Fee based / Quoted
	Pre-connection consultation services	Quoted
Connection Services	Large customer connections	Quoted
	Commissioning and energisation of large customer connections	Quoted
	Real estate development connection	Quoted
	Removal of network constraint for embedded generator	Quoted
	Temporary connections	Fee based
Post Connection Services	Connection management services (post connection)	Fee based / Quoted
	Accreditation of alternative service providers and approval of their designs, works and materials	Fee based / Quoted
Metering Services	Auxiliary Metering Services	Quoted
	Type 5 and 6 meter installation and provision (on or after 1 July 2015), where the new or upgraded meter is required as a result of a customer request	Fee based / Quoted
Ancillary Network Services	Services provided in relation to a ROLR event	Quoted
	Other recoverable works	Fee based / Quoted

Once this distinction is made, the prices for each service will be calculated in accordance with the proposed formulae (see Section 5.4). Actual prices for fee based services and example prices for quoted services will be provided in our annual Pricing Proposals.

### 5.7.3 Fee based services

There are a number of one-off services which Ergon Energy undertakes at the request of identifiable customer or retailer which are relatively standard in nature (e.g. de-energisations and re-energisations). This means the costs of providing the service can be assessed in advance of the service being requested.

Ergon Energy proposes to adopt an approach consistent with the regulatory control period 2010-15 in determining prices for fee based services. We will charge for:

- the cost of labour by applying labour rates previously approved by the AER in 2014-15 (escalated annually).<sup>79</sup> The cost of labour includes fleet on-costs and labour on-costs, which comprise the costs associated with payroll tax, superannuation, annual leave entitlements, sick leave entitlements, statutory holidays (special leave) and worker's compensation. The labour on-cost rates will be calculated annually. Overheads will also be calculated annually in accordance with Ergon Energy's CAM

<sup>79</sup> Except for the administration labour rate. Ergon Energy has adopted the rate set out in the AER's Preliminary Determination.

- the costs of materials by applying Ergon Energy’s models based on the materials used in the provision of each individual fee based service (where relevant). These costs are obtained from a combination of our supply system, period contract rates (where available), suppliers and other third party organisations. For materials held in stock, a materials on-cost will also be applied. This rate will be calculated annually. Overheads will also be calculated annually in accordance with the CAM
- the capital costs associated with fleet<sup>80</sup> and other non-system assets, by calculating an amount in accordance with the value of these assets used in the provision of fee based services and quoted services
- the Goods and Services Tax (GST) in accordance with relevant legislation.

Further information on our approach to determining prices for fee based services is provided in our supporting document *05.05.01 – (Revised) Inputs and assumptions for Alternative Control Services*.

Table 36 sets out the indicative prices for our fee based services for each year of the regulatory control period 2015-20, as required by clause 6.8.2(c)(4) of the NER. Prices for 2015-16 were approved by the AER in the 2015-16 Pricing Proposal, with the exception of the “Install new or replacement meter” services which are new fee based services.

**Table 36: Indicative prices for fee based services, by service 2015-20**

Pricing category \$/unit (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Application fee - Basic or standard connection	852.23	887.61	899.80	923.81	948.92
Application fee - Basic or standard connection - Micro-embedded generators	46.63	47.96	49.32	50.72	52.16
Application fee - Basic or standard connection - Micro-embedded generators - Technical assessment required	211.71	220.92	223.42	229.31	235.51
Application fee - Real estate development connection	892.30	929.60	942.07	967.17	993.44
Protection and Power Quality assessment prior to connection	1,320.64	1,383.71	1,392.79	1,428.72	1,466.80
Temporary connection, not in permanent position - single phase metered - urban/short rural feeders	561.13	587.58	591.30	606.26	622.15
Temporary connection, not in permanent position - single phase metered - long rural/isolated feeders	897.80	940.13	946.08	970.01	995.43
Temporary connection, not in permanent position - multi phase metered - urban/short rural feeders	561.13	587.58	591.30	606.26	622.15
Temporary connection, not in permanent position - multi phase metered - long rural/isolated feeders	897.80	940.13	946.08	970.01	995.43

<sup>80</sup> Excluding depreciation, which is included in the fleet on-cost.

Pricing category \$/unit (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Supply abolishment during business hours - urban/short rural feeders	336.68	352.55	354.78	363.75	373.29
Supply abolishment during business hours - long rural/isolated feeders	673.35	705.10	709.56	727.51	746.58
De-energisation during business hours - urban/short rural feeders	94.03	98.41	98.98	101.44	104.05
De-energisation during business hours - long rural/isolated feeders	561.13	587.58	591.30	606.26	622.15
Re-energisation during business hours - urban/short rural feeders	74.77	78.25	78.71	80.66	82.74
Re-energisation during business hours - long rural/isolated feeders	522.97	547.63	551.09	565.03	579.84
Re-energisation during business hours - after de-energisation for debt - urban/short rural feeders	74.77	78.25	78.71	80.66	82.74
Re-energisation during business hours - after de-energisation for debt - long rural/isolated feeders	522.97	547.63	551.09	565.03	579.84
Accreditation of alternative service providers - real estate developments	866.67	908.06	914.02	937.60	962.59
Prevented access - one person crew - urban/short rural feeders	52.43	54.87	55.19	56.55	58.00
Prevented access - one person crew - long rural/isolated feeders	209.74	219.48	220.74	226.19	232.00
Prevented access - two person crew - urban/short rural feeders	108.01	113.10	113.82	116.69	119.75
Prevented access - two person crew - long rural/isolated feeders	432.06	452.42	455.27	466.77	479.00
Install new or replacement meter (Type 5 and 6) – Single phase – urban/short rural feeder	331.70	345.65	346.11	353.14	360.64
Install new or replacement meter (Type 5 and 6) – Single phase – long rural/isolated feeder	514.25	536.74	538.33	550.12	562.71
Install new or replacement meter (Type 5 and 6) – Dual element – urban/short rural feeder	406.27	422.92	423.05	431.21	439.93
Install new or replacement meter (Type 5 and 6) – Dual element – long rural/isolated feeder	588.82	614.01	615.27	628.19	642.00
Install new or replacement meter (Type 5 and 6) – Three phase – urban/short rural feeder	510.66	531.13	530.81	540.52	550.93
Install new or replacement meter (Type 5 and 6) – Three phase – long rural/isolated feeder	693.21	722.22	723.03	737.50	753.00
Install new or replacement meter (CT) – urban/short rural feeder	2,426.06	2,526.93	2,529.05	2,579.13	2,632.64
Install new or replacement meter (CT) – long rural/isolated feeder	2,775.35	2,892.71	2,897.16	2,956.54	3,019.95



It should be noted that the Queensland Government has set maximum price caps to apply to a subset of our Alternative Control Services through Schedule 8 of the *Electricity Regulation 2006 (Qld)*. Since the price caps are imposed through legislation, they take precedence over prices approved by the AER. Our annual *Price List for Alternative Control Services* will set out the services impacted by Schedule 8 and the respective capped prices.

#### 5.7.4 Quoted services

Quoted services encompass those services Ergon Energy undertakes at the request of an identifiable customer or retailer that vary in the nature and scope of work, depending on the requestor's needs.

Ergon Energy proposes to adopt an approach consistent with the regulatory control period 2010-15 in determining prices for quoted services. We will charge for:

- the cost of labour by applying labour rates approved by the AER in 2014-15 (escalated annually).<sup>81</sup> The cost of labour includes fleet on-costs and labour on-costs, which comprise the costs associated with payroll tax, superannuation, annual leave entitlements, sick leave entitlements, statutory holidays (special leave) and worker's compensation. The labour on-cost rates will be updated annually. Overheads will also be calculated annually in accordance with Ergon Energy's CAM
- contractor services at the cost they arise in the provision of each individual quoted service. Overheads will be calculated annually in accordance with the CAM
- the costs of materials by applying Ergon Energy's models based on the materials used in the provision of each individual quoted service. These costs are obtained from a combination of our supply system, period contract rates (where available), suppliers and other third party organisations. For materials held in stock, a materials on-cost will also be applied. This rate will be calculated annually. Overheads will also be calculated annually in accordance with the CAM
- the capital costs associated with fleet<sup>82</sup> and other non-system assets, by calculating an amount in accordance with the value of these assets used in the provision of fee based and quoted services. For the design and construction of connection assets for major customers, Ergon Energy has applied an additional margin to the general capital allowance rate, to promote greater competition in the provision of this service
- GST.

Further information on our approach to determining indicative prices for quoted services is provided in our supporting document *05.05.01 – (Revised) Inputs and assumptions for Alternative Control Services*.

Given the nature of quoted services, it is not possible to provide examples of typical or representative services. This is because the actual prices for these services will be determined at the time of the customer's enquiry and will reflect the actual requirements of the service.

However, in order to demonstrate the application of the control mechanism, Ergon Energy has provided a worked example of the calculation of charges for one of our quoted services. This

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<sup>81</sup> Except for the administration labour rate. Ergon Energy has adopted the rate set out in the AER's Preliminary Determination.

<sup>82</sup> Excluding depreciation, which is included in the fleet on-cost.



worked example and indicative prices for other quoted services are provided in our supporting document *05.05.01 – (Revised) Inputs and assumptions for Alternative Control Services*.

As noted above, maximum price caps may apply to some of these services as a result of Schedule 8 of the *Electricity Regulation 2006 (Qld)*. Our annual *Price List for Alternative Control Services* will set out the services impacted by Schedule 8 and the respective capped prices.

## 5.8 Assigning customers to tariff classes

*Ergon Energy proposes a number of changes to the procedures for assigning and reassigning retail customers to Alternative Control Service tariff classes. We consider it is not practical to notify retailers of tariff class assignments and reassignments since customers or retailers essentially assign themselves to tariff classes.*

Assignment or reassignment of customers to Ergon Energy's Alternative Control Services can occur as a result of:

- major customers requesting a new connection to the network or an upgrade to their existing connection
- public lighting customers requesting installation of a new public light, or gifting a new public light to Ergon Energy
- small customers requesting a change to their metering arrangements (e.g. installing controlled load or solar, or choosing another provider if competition is introduced)
- new service orders or works requests being raised as a result of a request for service by either a customer and/or retailer
- requests for a review of the assigned tariff class by either a customer and/or retailer.

Tariffs for Alternative Control Services will be allocated to tariff classes in accordance with the AER's classification of services for the regulatory control period 2015-20. As such, customers and retailers essentially assign themselves to a tariff class by selecting the service that they require. Ergon Energy therefore considers we meet the requirements of clauses 6.18.4(a)(1), (2) and (3) of the NER because the tariffs within each tariff class are provided to customers that have similar service requirements, without distinguishing between customers that have or do not have micro-generation facilities.

Ergon Energy proposes to follow the procedures for assigning or reassigning customers to tariff classes detailed in our submission response, *SCS Building Blocks, Control Mechanism and Pricing – Response*.

Ergon Energy has an effective system for assessing and reviewing an assignment or reassignment decision, as required under clause 6.18.4(4) of the NER. Details of these procedures are set out in our *Information Guide for Alternative Control Services Pricing*.<sup>83</sup>

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<sup>83</sup> Available at [www.ergon.com.au/networktariffs](http://www.ergon.com.au/networktariffs).

## 5.9 Supporting documentation

The following documents referenced in this chapter accompany our Regulatory Proposal:

Name	Ref	File name
(Revised) Classification Proposal	02.01.01	(Revised) Classification Proposal
(Revised) Compliance with Control Mechanisms	04.01.00	(Revised) Compliance with Control Mechanisms
(Revised) Public Lighting Services Summary	05.01.01	(Revised) Public Lighting Summary
(Revised) Public Lighting Services PTRM	05.02.03	(Revised) PLPTRM Data Model with Prices
(Revised) Default Metering Services Summary	05.03.01	(Revised) Default Metering Services Summary
(Revised) Default Metering Services PTRM	05.04.07	(Revised) MTPTRM Data Model
(Revised) Inputs and assumptions for Alternative Control Services	05.05.01	(Revised) Inputs and assumptions for ACS
SCS Building Blocks, Control Mechanism and Pricing – Response	N/A	Ergon Energy – SCS Building Blocks, Control Mechanism and Pricing – Response
Alternative Control Services (Other) – Response	N/A	Ergon Energy – Alternative Control Services (Other) – Response
Metering – Response	N/A	Ergon Energy – Metering – Response

# Appendix A: Operating expenditure forecasts for Standard Control Services

## Introduction and summary of changes

Our operating expenditure program is critical to delivering a safe, dependable service.

We have achieved significant efficiency improvements in recent years, which have placed us well to deliver savings into 2015-20. However, the targets we have set for our operating costs are a challenge and will require significant reduction in costs in the future to deliver. We are looking to technology-based capabilities to support greater efficiencies moving forward.

We are increasing our operating expenditure on alternative non-network solutions to better manage demand on the network, as an alternative to capital investment, and looking at a new form of cyclone insurance cover.

Our base year has been updated to 2013-14. We have also changed our approach to making adjustments to the base year.

## Customer benefits

Our operating expenditure program is critical to delivering on the full set of our service commitments to regional Queensland – most importantly to our safety and reliability commitments. This expenditure is also critical to our disaster management and storm/outage response capability, as well as to delivering on our guaranteed service levels. It also allows us to best support customer choice in economic electricity supply solutions.

We are aiming to continue to drive efficiencies, without compromising on our service standards.

Expenditure on alternative non-network solutions is central to delivering on our overall best possible price commitment, and our cyclone insurance cover proposal is about reducing the potential for a significant price shock impact if one or more of Queensland's coastal population centres is devastated by a major cyclone.

## Appendix A: Operating expenditure forecast for Standard Control Services

### 1 Overview

Our revised forecast of operating expenditure requirements is substantially lower than our actual and estimated spend in the regulatory control period 2010-15 and lower than our October Regulatory Proposal. It incorporates efficiencies in vegetation management, line inspection and pole defect management. We will also continue to use non-network alternatives where possible to avoid employing costly capital solutions in line with NER requirements.

We outline in a number of supporting documents the reductions we have made to recurrent activity. This has led to us providing better price outcomes for customers in the regulatory control period 2015-20. We are also confident that we can leverage the initiatives and technologies we have been implementing recently and these will deliver even better outcomes in the next five years. Rather than seek to share these benefits over time through the traditional incentive mechanism arrangements, we have sought to deliver these through a reduction in overhead expenditure allowance in the first year of the period. We have done this in consideration of customer preferences for price relief now as well as other influencing factors.

There will be increases in some areas of expenditure, but we believe they represent the following:

- a need to comply with new regulatory obligations
- a trade-off against returns though the RAB for expenditure already incurred
- appropriate capital/operating expenditure trade-offs, and/or
- a trade-off against volatility in expenditure and prices when Ergon Energy's network is adversely affected by cyclone damage.

In summary, our forecasts include a new form of insurance cover given our unique exposure to extreme wind-generated events like Cyclone Yasi. We have also updated our forecasts to incorporate the anticipated costs of meeting new regulatory obligations through our Market Transaction Centre, as the Minimalist Transitioning Approach reaches an end.

The total operating expenditure Ergon Energy requires to meet the operating expenditure objectives in the regulatory control period 2015-20 is provided below.

Table 37: Forecast operating expenditure, 2015-20

\$'000 (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Operating expenditure	334,020	346,600	358,180	365,890	374,320	1,779,010

This appendix outlines:

- why Ergon Energy incurs this level of operating expenditure, and the various categories of expenditure that make up Ergon Energy's operating program
- our level of operating expenditure in the regulatory control period 2010-15 and how it compares to the efficient level of operating expenditure set by the AER for that period

- factors influencing our operating expenditure in the regulatory control period 2015-20
- our methodology, approach and assumptions underpinning our forecasts
- outcomes for customers as a result of our forecasts
- how our operating expenditure forecasts satisfy the operating expenditure criteria, having regard to the factors outlined in the NER.

Appendix E separately details our proposal in relation to the need for the AER to apply a transition path in the scenario where the AER rejects our proposal and substitutes it with a much lower forecast.

## 2 Components of our operating expenditure requirement

### 2.1 Direct operating expenditure

The components of our direct operating expenditure program are illustrated in Figure 8.

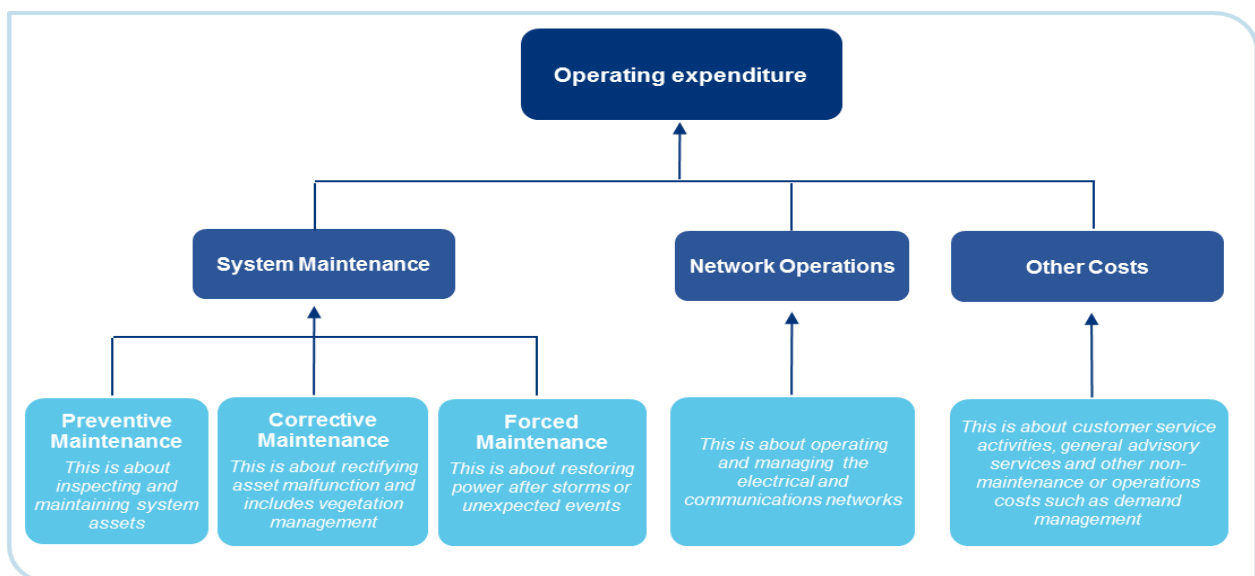


Figure 8: Components of our operating expenditure requirement

Ergon Energy’s direct operating expenditure requirements are driven by Ergon Energy’s customer commitments, regulatory and statutory requirements, codes of works and industry standards. The content of the network operating expenditure program balances these requirements within the funding proposed through:

- compliance with all applicable regulatory obligations or requirements
- maintaining the reliability, safety, and security of the distribution system
- managing the forecast demand for Standard Control Services reviewing cost and risk.

**Network Maintenance:** comprises of scheduled (routine) and non-scheduled (non-routine) inspection and maintenance activity across all Ergon Energy asset categories.

**Network Operations:** covers operating expenditure costs incurred or associated with the safe, effective, and reliable operation of the electricity network. The two primary components of network operations are:

- Network Operations that comprise the operational expenditure required to resource and operate Ergon Energy’s network control centres
- System Operations that comprise the operational expenditure required to provide services such as system communications, operational technology software and related expenditure.

**Other Operating Costs:** includes customer service activity such as education and customer contact in respect of electrical safety issues and other general advisory services.

In the regulatory control period 2010-15, this expenditure category also included meter reading costs associated with Ergon Energy’s role as a Metering Data Provider for Types 5 and 6 metering installations. However, these costs will not be included in the operating expenditure requirement in the regulatory control period 2015-20 as Default Metering Services will be classified as an Alternative Control Service. This means the costs of reading a Type 5 or 6 meter will be recovered as a separate charge from customers (where applicable).

Other operating costs also include demand management, which includes a range of non-network alternative solutions, as a tactical response to network problems – primarily where growing customer peak demand requirements create the need to expand network capacity.

Table 38 shows that our total operating expenditure over the regulatory control period 2015-20 is expected to be 2.31% lower than our October Regulatory Proposal.

**Table 38: Comparison between October and revised Regulatory Proposals, operating expenditure, 2015-20**

\$'000 (real 2014-15)	October Regulatory Proposal	Revised Regulatory Proposal	% difference
Total forecast operating expenditure	1,821,130	1,779,010	(2.31%)

Further information on the forecast expenditure for each category is provided in the supporting document *06.01.01 – (Revised) Operating Forecast Expenditure Summary Document (Opex Forecast Summary)*.

## 2.2 Overheads or support expenditure

Like all businesses, Ergon Energy accounts for a large portion of our costs as support expenditure or overhead. By their nature, these costs are allocated to direct cost activities (capital and operating expenditure, as well as to other services) consistent with a CAM approved by the AER. A full list of the overhead functional areas can be found in Attachment 1 of the supporting document *06.01.01 – (Revised) Opex Forecast Summary*. Examples of overhead costs include:

- Administrative Support
- Corporate Support
- Customer Service and Billing
- Engineering Standards, Technology and Support
- Finance
- Fleet
- Human Resources

- ICT
- Network Planning
- Network Safety
- Property.

### 3 Prior period performance

Table 39 and Table 40 provide Ergon Energy's actual operating expenditure for each year of the previous two regulatory control periods, disaggregated by program of expenditure.<sup>84</sup> Information provided for both regulatory control periods are based on the CAM applying in the regulatory control period 2010-15. Expenditure associated with FiT payments has been excluded from the prior period performances. These costs do not form part of our Direct Control Services from 1 July 2015.

**Table 39: Operating expenditure by category, 2005-10**

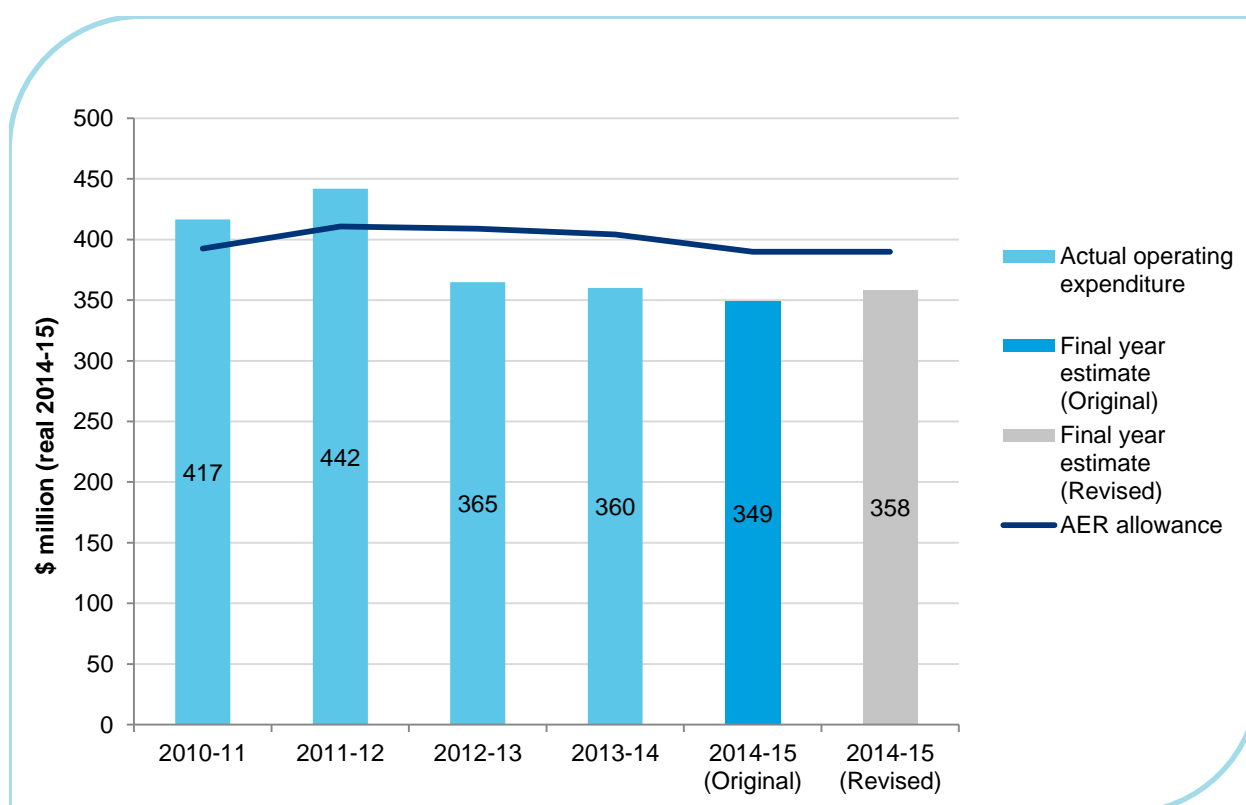
<b>\$'000 (real 2014-15)</b>	<b>2005-06</b>	<b>2006-07</b>	<b>2007-08</b>	<b>2008-09</b>	<b>2009-10</b>	<b>Total</b>
<b>Network Operating Costs</b>						
Network Operating Costs	20,067	30,804	36,157	35,709	33,154	155,891
<b>Network Maintenance Costs</b>						
Preventive Maintenance	64,454	68,736	114,756	104,269	77,516	429,732
Corrective Maintenance	99,981	132,078	85,117	98,768	114,012	529,954
Forced Maintenance	65,946	25,231	50,079	50,776	63,952	255,984
<i>Subtotal</i>	<i>230,381</i>	<i>226,045</i>	<i>249,951</i>	<i>253,813</i>	<i>255,479</i>	<i>1,215,670</i>
<b>Other Costs</b>						
Meter Reading	10,687	12,539	12,512	15,298	13,231	64,266
Customer Services	39,860	33,638	29,668	20,475	20,503	144,143
Other Operating Costs	22,662	24,054	22,328	26,786	22,639	118,470
<i>Subtotal</i>	<i>73,209</i>	<i>70,231</i>	<i>64,508</i>	<i>62,559</i>	<i>56,373</i>	<i>326,879</i>
<b>Total actual operating expenditure</b>	<b>323,657</b>	<b>327,080</b>	<b>350,616</b>	<b>352,081</b>	<b>345,006</b>	<b>1,698,440</b>

<sup>84</sup> NER, clause S6.1.2(7).

**Table 40: Operating expenditure by category, 2010-15**

\$'000 (real 2014-15)	2010-11	2011-12	2012-13	2013-14	2014-15 (estimate)	Total
<b>Network Operating Costs</b>						
Network Operating Costs	36,168	35,075	34,775	35,241	33,997	175,257
<b>Network Maintenance Costs</b>						
Preventive Maintenance	83,105	103,534	92,096	73,440	72,449	424,624
Corrective Maintenance	117,323	147,271	113,905	107,694	103,592	589,784
Forced Maintenance	105,368	67,059	73,115	69,413	66,652	381,607
<i>Subtotal</i>	<i>305,795</i>	<i>317,864</i>	<i>279,116</i>	<i>250,547</i>	<i>242,693</i>	<i>1,396,015</i>
<b>Other Costs</b>						
Meter Reading	12,985	14,282	13,330	13,195	14,186	67,978
Customer Services	20,980	27,338	32,389	26,125	31,580	138,413
Other Operating Costs	40,654	47,193	5,073	35,056	36,001	163,978
<i>Subtotal</i>	<i>74,619</i>	<i>88,813</i>	<i>50,793</i>	<i>74,377</i>	<i>81,767</i>	<i>370,368</i>
<b>Total actual operating expenditure</b>	<b>416,582</b>	<b>441,752</b>	<b>364,683</b>	<b>360,165</b>	<b>358,457</b>	<b>1,941,640</b>

As illustrated in Figure 9, Ergon Energy expects to deliver an operating program less than the AER approved allowance over the regulatory control period 2010-15.



**Figure 9: Comparison of operating expenditure, 2010-15**



### 3.3 Key drivers of expenditure and outcomes in the previous period

#### Impacts of response and recovery

While lightning, storm activity, flooding, heavy rain and high wind drive a material amount of our traditional operating expenditure requirements, there are some events we simply cannot predict. The summer storm season of 2010-11 represented one of the worst seasons in our history. On 3 February 2011, Queensland was hit by the largest storm system in living memory – Cyclone Yasi. Cyclone Yasi crossed the Queensland coast at Mission Beach as a Category 5 cyclone, over 600 kilometres wide, with wind speeds of 295 kilometres per hour. It took out power supplies to nearly a third of our customer base, interrupting over 220,000 homes and businesses, and at least 50 major substations were off supply as part of the initial impact.

Cyclone Yasi also impacted other programs of work. This combined with other major weather events (flooding and impacts from ex-Cyclone Oswald, and Cyclone Marcia) saw substantial increases against forecasts in some cost categories.

#### Increased focus on cost reductions

Despite substantial pressures and necessary expenditure from response and recovery efforts, we made deliberate and significant reductions to our underlying costs which resulted in us spending less than the operating expenditure allowance set by the AER (as shown in Figure 9 above).

Our supporting document, *06.01.02 – (Revised) System Related Operating Expenditure Summary*), outlines a number of deliberate initiatives aimed at improving outcomes for customers in terms of cost reductions. This included:

- developing and implementing, in partnership with Energex, a robust asset management framework, followed by a review of all maintenance programs with subsequent risk assessments. This resulted in the consolidation of programs, and improvements in out-turn expenditure
- efficiency improvements in maintenance program delivery and management.

Our supporting document, *Ergon Energy's Journey to the Best Possible Price (Best Possible Price)*,<sup>85</sup> notes the efficiency and effectiveness initiatives undertaken during this period. These initiatives, covering both direct and indirect expenditure, covered all elements of the business and were supported by an organisational restructure and adjustment to the workforce (employees and contractors) of over 600 positions.

During 2013-14 and 2014-15, Ergon Energy has been focused on delivering network services on budget (i.e. in accordance with 2012-13 adjusted levels) while establishing frameworks that will drive future cost savings. The outcomes to date from this continual focus on efficiency and effectiveness have included:

- signing off a new business direction and model
- implementing a new executive and senior management structure
- reducing total expenditure spend by over 20% against the regulatory allowance
- contracting business headcount substantially

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<sup>85</sup> *0A.01.02 – (Revised) Ergon Energy's Journey to the Best Possible Price.*

- success in securing new security and reliability standards that will ease investment.

### Reliability of the network continued to improve

Throughout this period of change, we continued to deliver strong performance outcomes for our customers, with improvements in our reliability measures across all distribution feeder types. This reflects the significant investment and operational priority we have placed over the regulatory control period 2010-15 on achieving the regulated Minimum Service Standards (MSS). The MSS includes two components:

- System Average Interruption Duration Index (SAIDI)
- System Average Interruption Frequency Index (SAIFI).

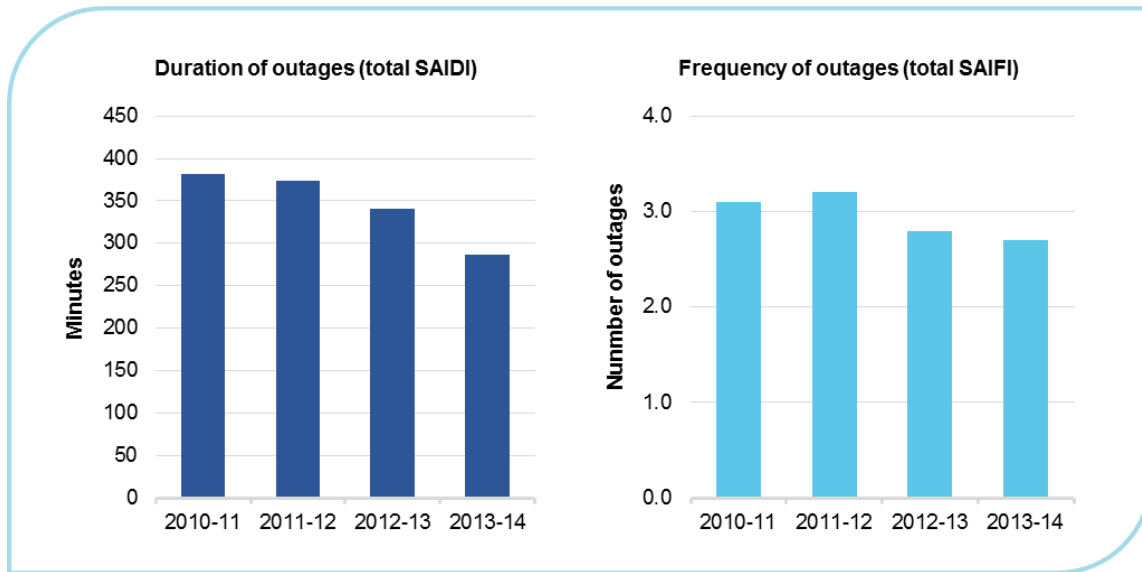


Figure 10: SAIDI and SAIFI, 2010-11 to 2013-14



Our customer engagement research is showing our customers are now generally satisfied with the level of supply they receive.<sup>86</sup> Our research has also highlighted that customers on the whole do not believe that future improvements in reliability are required, particularly not at the expense of higher prices. As such, moving forward, our operating expenditure plans focus on maintaining reliability rather than making further broad-based improvements in this area.

## 4 Factors influencing forecasts in 2015-20

This section considers the factors and challenges driving operating expenditure in the regulatory control period 2015-20 and the way in which we propose to respond.

<sup>86</sup> Refer to our supporting document 0A.01.04 – *Informing our plans, Our Engagement Program*.

Operating expenditure is largely recurrent by nature, which means that actual operating expenditure incurred in previous years is typically viewed by the AER as an appropriate starting point for the calculation of efficient future requirements. Our forecasting methodology, which is based on a revealed cost approach, recognises this principle.

Nevertheless, in order for Ergon Energy to ensure that our operating expenditure forecasts enable us to achieve the operating expenditure objectives, it is necessary to examine the factors that will materially influence our operating expenditure over the regulatory control period 2015-20.

#### **4.1 Our journey to the best possible price**

For some time now, we have delivered substantial savings across our operating program, particularly in the areas of overhead cost reduction and workforce optimisation. Our focus on driving efficiencies has continued until the end of the regulatory control period 2010-15. The changes will provide Ergon Energy with a further opportunity to review the way we will meet customers' expectations around reliability, performance and the range of services provided. Additional efficiency savings are expected to be leveraged through the implementation of new management structures, driving a culture of operational and financial efficiency.

We have also been undertaking further analysis on the evolving operating environment, anticipated regulatory and policy changes, future economic conditions and trends in energy consumption, innovation and customer expectations to identify where further efficiencies can be achieved.

Our *Best Possible Price* document outlines how, in addition to reductions already made in the regulatory control period 2010-15, Ergon Energy has incorporated further reductions to our forecast operating expenditure requirement to deliver lower price outcomes for customers. As discussed in detail in the forecast methodology in Section 5, this adjustment takes the form of an upfront one-off adjustment to the operating expenditure required in the first year of our regulatory control period 2015-20.

#### **Bringing forward future benefits for customers**

The AER has stated that our decision to reduce forecast operating expenditure represents acknowledgement that expenditure in the base year is inefficient. This is a mischaracterisation of our forecasts and the incentive framework within which we operate. Normally, under the existing regulatory framework, any prospective benefits or cost reductions from innovation or other initiatives would be shared with customers in future regulatory control periods. In other words, proactive attempts to reduce costs would be passed on to customers over time.

We want to do more.

Ergon Energy is committed to improving the affordability of electricity for our customers, while not compromising safety and reliability. Based on our customer engagement activities we understand the majority of residential customers would prefer to see prices unchanged and for small businesses to see an immediate reduction in electricity prices.

With this in mind, Ergon Energy has prepared our forecasts in a way that passes on the anticipated savings from the above regulatory, structural and technological changes to our customers, in full and at the start of the regulatory control period (i.e. 2015-16).

Our approach does not unnecessarily delay the bringing forward of benefits for customers in terms of making sustainable price reductions and strikes an appropriate balance with the incentives Ergon Energy will experience under the EBSS. Feedback from customers and other key stakeholders (including the CCP) also indicates there is support for energy companies to deliver

the best possible price to customers as soon as possible, and not unduly defer or delay the sharing of benefits.<sup>87</sup>

Attaining this level of reduction during the period represents a challenge for the organisation, but one which we believe can be achieved while meeting all of our regulatory and safety obligations. Further, while price is a key issue for customers, we are cognisant of our customers' expectations around network safety, reliability and being able to respond to whatever Mother Nature delivers.

### Overall network reliability

As noted earlier, we have made good in-roads into improving the day-to-day reliability of our network. Our customer engagement has identified that our customers are now generally satisfied with the level of reliability we provide. As such, we will shift our focus in the regulatory control period 2015-20 from making further improvements in reliability to maintaining the current level of supply. This will create downward pressure on the operational expenditure required for reliability works.

### AER benchmarking report

The AER published its annual benchmarking report on 27 November 2014.<sup>88</sup> Due to the timing of its release, Ergon Energy was unable to examine the report and consider the findings in developing our initial forecasts. Since then, we have examined the AER's approach to benchmarking and made submissions to the AER through the NSW and Queensland regulatory determination processes.

## 5 Forecast methodology

In the previous sections we identified the forecast operating expenditure requirements for the regulatory control period 2015-20 and the drivers that influenced this program of work. This section provides an overview of the approach that we have adopted in developing these forecasts.

In support of this section we have also prepared our *Opex Forecast Summary* document,<sup>89</sup> which provides more detailed information and analysis on the methodologies applied. In addition to this, we submitted our Expenditure Forecast Methodology to the AER on 29 November 2013,<sup>90</sup> setting out our approach for forecasting expenditure for the regulatory control period 2015-20, including our approach to operating expenditure. This section should therefore be read in conjunction with these documents.

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<sup>87</sup> 0A.01.04 – *Informing our plans, Our Engagement Program*; Consumer Challenge Panel (2014a), *Current and Emerging Issues for the Queensland Distributors' Revenue Determinations*, Queensland Consumers' Meeting 8 August 2014, <http://www.aer.gov.au/sites/default/files/Consumer%20Challenge%20Sub-Panel%20202%20%28Hugh%20Grant%29%20-%20Presentation%20to%20Qld%20consumer%20forum%20-%20208%20August%202014.pdf>; Consumer Challenge Panel (2014b), *Smelling the Roses and Escaping the Rabbit Holes: the Value of Looking at Actual Outcomes in Deciding WACC*, Prepared for the Board of the Australian Energy Regulator, July 2014, <https://www.aer.gov.au/sites/default/files/CCP%20report%20prepared%20for%20AER%20Board%20-%20Rate%20of%20Return.pdf>; Ergon Energy (2014), Customer Council AER2015 Working Group Meeting Notes, 28 August 2014, [https://www.ergon.com.au/data/assets/pdf\\_file/0004/218416/Customer-Council-AER2015-Working-Group-August-meeting-notes.pdf](https://www.ergon.com.au/data/assets/pdf_file/0004/218416/Customer-Council-AER2015-Working-Group-August-meeting-notes.pdf).

<sup>88</sup> AER (2014), *Electricity distribution network service providers, Annual benchmarking report*, November 2014.

<sup>89</sup> 06.01.01

<sup>90</sup> Refer to <https://www.ergon.com.au/network/network-management/future-investment/future-direction>.

## 5.1 Key assumptions

Table 41 outlines the key assumptions underpinning our operating expenditure forecasts for the regulatory control period 2015-20, consistent with NER requirements.<sup>91</sup> Except for the change to the base year, there have been no material changes since our October Regulatory Proposal. In June 2015, the directors of Ergon Energy reviewed the key assumptions and confirmed their continued application for this revised Regulatory Proposal.

**Table 41: Operating expenditure assumptions, 2015-20**

Assumption	Application
Our current company structure, ownership arrangements and service classification will continue.	The operating expenditure forecasts are based on continuing the current company structure. Any future restructuring could change Ergon Energy's cost structure and would require changes to our CAM.
Our current legislative and regulatory obligations will not change materially.	The operating expenditure forecasts are designed to comply with the current legislative and regulatory obligations. If any material changes occur, they may be treated as a cost pass through event.
The AER will not depart from its preference stated in the Expenditure Forecast Assessment Guideline for network service providers (NSPs) to justify operating expenditure allowances using a BST methodology.	Ergon Energy has prepared our forecasts consistent with a BST methodology based on AER requests, both directly to Ergon Energy and through its Expenditure Forecast Assessment Guideline. We have taken into account the need for our forecasts to be consistent with our CAM, and have modified our methodology to be consistent with this. We also explained exceptions to adopting a BST for some operating expenditure functional areas.
The 2013-14 audited financial statements are an appropriate starting point for the establishment of an efficient base year.	The 2013-14 financial year represented the most recent audited financial statements available for the purpose of forecasting for the regulatory control period 2015-20 to meet the timetable for submission to the AER on 3 July 2015 and the most logical representative base year.
Adjustments to the base year expenditure are necessary and reasonable.	Consistent with a BST methodology, base year expenditure has been adjusted to account for non-recurring expenditure, step changes and other one-off adjustments to ensure our expenditure forecast meets NER requirements.
Rate of change factors applied for the period are realistic and reasonable.	Consistent with a BST methodology, we have applied input (price), output (driver) and productivity growth factors to the base year forecast. We have based these rate of change factors on independent expert advice and/or industry or regulatory precedents, including expert advice from Jacobs (SKM) that is included as an attachment supporting this Regulatory Proposal. <sup>92</sup> This approach ensures that these escalators appropriately reflect the increases in the cost of materials and other non-labour inputs, as well as the skills required and the market factors driving the demand and supply of labour for the provision of our services.

<sup>91</sup> NER, Schedule 6.1.2(5). Schedule 6.1.2(6) also requires the directors of Ergon Energy to certify the reasonableness of these assumptions. This is available at 06.01.06 – *Certification of reasonableness – expenditure forecast assumptions*.

<sup>92</sup> 06.02.02 – *Jacobs: Cost Escalation Factors 2015-20* and 06.02.07 – *Jacobs: Addendum Cost Escalation Factors 2015-20*.

Assumption	Application
Our parametric insurance will cover the financial impact of extreme wind-generated weather events and our works delivery and expenditure requirements will not be materially disrupted by extreme weather events.	Extreme weather events, such as cyclones or major flood events, can interfere with our ability to implement planned operating expenditure programs such as inspections and maintenance. Appropriate adjustments to our base year forecast operating expenditure have been made to allow for the impacts of the costs of our parametric insurance proposal being included in the Regulatory Proposal forecasts for the regulatory control period 2015-20.

## 5.2 Revised approach to forecasting operating expenditure

Ergon Energy has traditionally prepared our operating expenditure forecasts through a bottom-up forecast of direct maintenance, operations and customer service costs, with overhead applied in a manner consistent with our CAM. This approach has generally been accepted by regulators in the past.

Our adoption of the BST methodology for forecasting the majority of our recurrent operating expenditure represents a substantial change in approach from that applied in developing our forecasts for the regulatory control period 2010-15. We have attempted to reconcile our approach with the AER's Expenditure Forecast Assessment Guideline,<sup>93</sup> but have found that some departures have been necessary.

*"...NSPs may find it useful to focus their approach to justifying their proposed opex allowances through the base-step-trend approach, if they have not used it in the past."*

*AER, Better Regulation, Explanatory Statement – Expenditure Forecast Assessment Guidelines for electricity transmission and distribution*

Ergon Energy undertakes recurrent activity across a number of our various business units. Relevant to the regulation of Standard Control Services, Ergon Energy broadly categorises our recurrent activity into:

- direct (recurrent) costs for Standard Control Services comprising the key network service elements of maintenance, operations and customer service
- shared (support) costs, often referred to as overhead activities (such as the Finance function), which are aggregated and spread across all of Ergon Energy's direct expenditure including:
  - direct operating expenditure
  - direct capital expenditure
  - in some circumstances across direct costs for Alternative Control Services, unregulated and unclassified services.

The allocation of the latter category is based on the AER's approved approach for allocation in the CAM. Because the AER has approved allocations in this manner, aggregate Standard Control Service base year costs cannot be trended in a linear manner. This is because the overhead portion of the Standard Control Service base year will vary based on the steps outlined above, even if the overhead cost item itself trends in a linear manner.

The AER's Expenditure Forecast Assessment Guideline and Preliminary Determination appear to ignore the CAM approved by the AER. Instead, it applies the Expenditure Forecast Assessment

<sup>93</sup> Refer to <http://www.aer.gov.au/node/18864#>.



Guideline which assumes the combination of direct and allocated overhead expenditure for Standard Control Services trend in a linear fashion. However, this cannot be done without changing the CAM. Given the provisions of clause 6.5.6(b)(2) of the NER take primacy over the AER's preferred method in the Expenditure Forecast Assessment Guideline, our proposal has necessarily departed from the approach the AER has taken in the Preliminary Determination.

Ergon Energy does not believe that the Guidelines or the AER's considerations give it prerogative to depart from arrangements the AER itself dictated when it approved Ergon Energy's CAM. In other words, the AER cannot be satisfied of a total operating expenditure forecast unless it has considered the arrangements under an approved CAM and has applied them appropriately. The AER cannot abrogate this responsibility merely because it has considered other relevant factors.

Ergon Energy's approach to forecasting operating expenditure remains consistent with what we proposed in October 2014. However, we have simplified our modelling arrangements. We have also attempted to simplify our operating expenditure requirement without substantially amending our methodology.

Figure 11 outlines the approach we have taken for the development of our operating expenditure forecasts. Ergon Energy has used a BST approach for our operating expenditure, with the exception of those Functional Areas identified in Section 5.4 below.

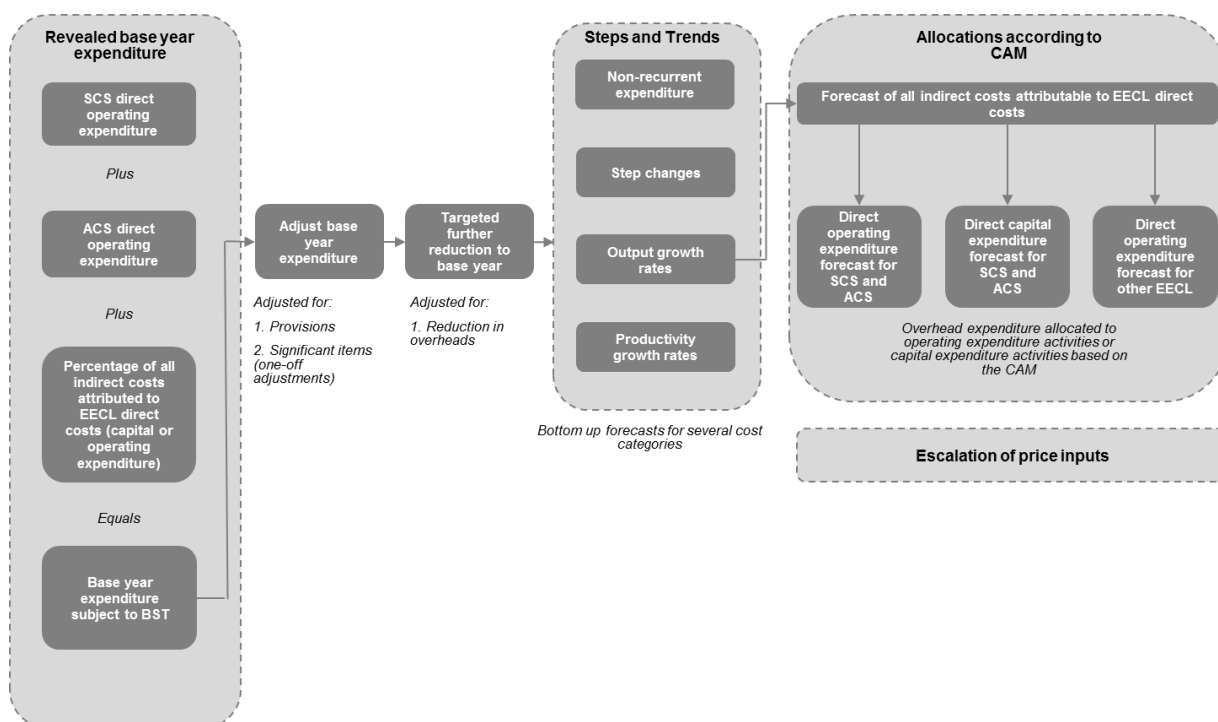


Figure 11: BST methodology

### 5.3 Base step trend forecasting approach

In simple terms, the BST methodology applied by Ergon Energy in preparing our operating expenditure forecasts involves:

- Step 1: Selecting a base year and identifying the reported Standard Control Service operating expenditure (inclusive of the overhead allocation to these costs) for that base year

- Step 2: Identifying separately the components of the reported Standard Control Service operating expenditure in the base year:
  - The Standard Control Services direct operating expenditure costs inherent within the reported base year
  - The indirect costs allocated to the Standard Control Services direct operating expenditure costs which have been applied in accordance with the AER's CAM approved for Ergon Energy
- Step 3: Preparing both direct operating expenditure and indirect (overhead) costs for BST forecasting. This involves:
  - Identifying the Functional Areas implicit within the costs forecasts
  - Aggregating overhead costs attributable to Standard Control Services with any other overhead cost that has been allocated to Ergon Energy's regulated activities (i.e. Standard Control Services capital expenditure, public lighting capital and operating expenditure, metering capital and operating expenditure, and other Alternative Control Service capital and operating expenditure)
- Step 4: For both direct operating expenditure and overhead costs, making necessary adjustments to base year costs so they can be used for forecasting. This includes:
  - adjustments for movements in provisions
  - one-off adjustments to the base year
  - other adjustments due to service reclassification
- Step 5: For both direct and overhead costs, identifying and applying any step changes or non-recurrent operating expenditure
- Step 6: For both direct and overhead costs, applying a rate of change to reflect changes in expenditure consistent with workload drivers Step 7: Applying relevant price escalation to both the direct and overhead component of each Functional Area cost
- Step 8: Allocating overhead costs back to each of the Functional Area direct costs in accordance with the CAM.

Each of these steps is briefly described below. More detailed information is available in the *Opex Forecast Summary* document.

### **Steps 1 and 2: Base year and approach to adjustments**

The initial step in developing operating expenditure forecasts under the BST method involves selecting a base year to be used as the basis upon which to build the forecast.

Ergon Energy has chosen the 2013-14 financial accounts as the base year for the purposes of forecasting operating expenditure for the Regulatory Proposal. 2013-14 was the fourth year of Ergon Energy's regulatory control period 2010-15 and represents the most recent financial year for which audited regulatory accounts were available at the time the operating expenditure forecasts were prepared.



This is consistent with the AER's expectations<sup>94</sup> and is appropriate given precedents to use the most up-to-date information.

### **Step 3: Identifying the components of the base year costs**

Ergon Energy has mapped our revealed costs from our audited 2013-14 financial data to groupings called 'Functional Area's for the purposes of our base year data. These Functional Areas are further mapped and combined into category level data for aggregate level reporting.

Some of the Functional Areas are, by nature, overhead activities. Where a Functional Area is an overhead cost, the overheads are aggregated and spread across all classifications, including Standard Control Services, Alternative Control Services, unregulated services and unclassified services.

For BST forecasting purposes, Ergon Energy identified the following Functional Areas that need to be mapped:

- direct Standard Control Services operating expenditure and Alternative Control Services operating expenditure
- overhead activities that are fully or partially attributed to direct Standard Control Services or Alternative Control Services activities.

The reported 2013-14 operating expenditure for Standard Controls Services includes both a direct operating expenditure portion and an allocation for overheads. The overhead allocation is determined in accordance with the CAM under a four step process.

Because the AER has approved allocations in this manner, the reported Standard Control Service operating expenditure base year costs cannot be trended in a linear manner. This is because the overhead portion of the Standard Control Service operating expenditure base year will vary based on the four step process, even if the overhead costs (as an aggregate item) trend in a linear manner.

Because of this, Ergon Energy needs to:

1. Separate our base year cost into both direct and indirect portions.
2. Aggregate the indirect portion with other Ergon Energy overhead costs attributable to all activities.
3. Trend the direct and indirect portions separately.
4. Reallocate the indirect portion back to direct costs in accordance with the allocation process.

### **Step 4: Adjustments to the reported base year costs**

Adjustments to the 2013-14 audited operating expenditure numbers have been made to remove expenditure incurred in the base year that does not support a recurrent cost for the purposes of forecasting. The adjustments may relate to specific one-off or unusual events (e.g. changes in service classification). Consistent with the Expenditure Forecast Assessment Guideline, Ergon Energy has also made adjustments to the base year operating expenditure to account for any movements in provisions. The removal of these items creates an efficient starting point or 'efficient base year' from which to commence the operating expenditure forecast. Our *Opex Forecast Summary* document details these adjustments.

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<sup>94</sup> AER (2013), *Email to Energex and Ergon Energy*, 4 March 2013.

## Step 5: Step changes and bottom up adjustments

We have incorporated areas of expenditure which were not captured in the base year but which are required, either in a certain year within the regulatory control period or on an ongoing basis. The step changes and other bottom up adjustments we have proposed relate to:

- the Market Transaction Centre. Base year expenditure does not include anticipated costs of meeting new regulatory obligations through our Market Transaction Centre, as the Minimalist Transitioning Approach reaches an end
- parametric insurance. Base year expenditure does not include expenditure relating to the efficient and prudent level of insurance required cover to mitigate the financial risks Ergon Energy faces in relation to damage caused to our electricity network by large scale storm and cyclone events. This is because historically there has been a lack of available and efficiently priced insurance cover in the insurance markets
- ICT Asset Service Fee. Base year expenditure does not include Asset Service Fee expenditure required in the regulatory control period 2015-20 for ICT capital works that were approved in the previous period but were delivered after the 2013-14 year
- ICT Operating Fee (to overhead costs). Ergon Energy has included increased operating expenditure for a range of systems required to operate in a fully contestable market.

Our supporting document *06.01.04 – (Revised) Step Changes for Operating Costs* provides further information on step changes and non-recurrent expenditure.

## Step 6: Trending base year expenditure for output growth

The AER recognises that distribution networks grow in size, and therefore face a corresponding increase in the cost associated with operating and maintaining the network. The annual growth rate of the network is determined with reference to network growth drivers that are considered to approximate the resultant growth in operating expenditure.

Ergon Energy has calculated two growth drivers:

- customer growth
- network growth.

In summary, Ergon Energy has not changed our approach to calculating workload drivers from our October Regulatory Proposal. However, growth factors have changed slightly based on updated information.

Ergon Energy has also incorporated a reduction in forecasts equivalent to 10% of our 2013-14 base year operating expenditure costs.<sup>95</sup> Additionally, we have applied an annual reduction of 0.75% to forecasting operating expenditure.<sup>96</sup>

Further information, including detailed analysis supporting the basis of the above drivers and reductions, is provided in the following documents supporting this appendix of the Regulatory Proposal:

- *Opex Forecast Summary* document

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<sup>95</sup> Excludes ICT and fleet related costs.

<sup>96</sup> Excludes ICT Asset Service Fee costs.

- supporting document 06.02.02 – Jacobs: Cost Escalation Factors 2015-20.<sup>97</sup>

### Step 7: Escalation for cost inputs

Ergon Energy has engaged Jacobs to develop real cost escalation factors for the four cost elements identified in the chart of accounts: labour, contractors, materials and other.

Ergon Energy dissects the 2012-13 base year costs into escalator categories and uses the revealed percentage split as a basis for forecasting any increases for the regulatory control period 2015-20.

We apply a two-step process to applying price escalation to our direct and overhead costs for forecasting purposes. This involves:

- de-escalating all of the costs in the BST model to 2012-13 dollars. This is because our capital expenditure inputs are in 2012-13 dollars. We convert all expenditure to common dollar un-escalated inputs in order to ensure allocation of overheads and price escalation occurs on a common dollar basis
- escalating all inputs (which are now in 2012-13 dollars) to 2014-15 dollars, using the relevant price escalators.

### Step 8: Forecast and allocation of overhead costs

The above steps provide a forecast for both direct operating expenditure and the Ergon Energy regulated overhead portion of the forecast. Table 42 below sets out the forecast direct operating expenditure.

**Table 42: Forecast direct operating expenditure (Standard Control Services)**

SCS operating expenditure forecast (\$m)	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
<b>RIN reported operating expenditure (\$13-14)</b>	<b>472.32</b>						
Less FIT (\$13-14)	(120.08)						
<i>Subtotal</i>	<i>352.24</i>						
Less overheads	(114.92)						
<b>Base year direct costs (\$13-14)</b>	<b>237.32</b>	<b>246.75</b>	<b>250.73</b>	<b>240.22</b>	<b>241.19</b>	<b>241.82</b>	<b>242.35</b>
Accounting adjustments	5.08						
CAM adjustments	4.35						
<b>Adjusted base year operating expenditure (\$13-14)</b>	<b>246.75</b>	<b>246.75</b>	<b>250.73</b>	<b>240.22</b>	<b>241.19</b>	<b>241.82</b>	<b>242.35</b>
Classification changes			(30.31)				
Adjustment for future efficiencies			(1.88)	(1.80)	(1.81)	(1.81)	(1.82)
Output growth		3.98	3.48	2.77	2.44	2.34	2.93

<sup>97</sup> This report is supported by 06.02.07 – Jacobs: Addendum Cost Escalation Factors 2015-20.

SCS operating expenditure forecast (\$m)	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
<i>Step changes and bottom up</i>							
Parametric insurance			13.00				
Market Transaction Centre			5.20				
<b>Operating expenditure before escalation (\$2013-14)</b>	<b>246.75</b>	<b>250.73</b>	<b>240.22</b>	<b>241.19</b>	<b>241.82</b>	<b>242.35</b>	<b>243.46</b>
2012-13 de-escalation amount	(7.19)	(7.30)	(7.00)	(7.02)	(7.04)	(7.05)	(7.08)
Real price growth direct operating expenditure			17.72	19.75	21.77	23.82	25.97
Overheads (\$2014-15)			83.07	92.68	101.63	106.78	111.96
<b>Total SCS operating expenditure forecast (\$2014-15)</b>		<b>243.43</b>	<b>334.01</b>	<b>346.59</b>	<b>358.18</b>	<b>365.89</b>	<b>374.31</b>

Ergon Energy has applied the BST methodology to forecast our total overhead (support) costs for the regulatory control period 2015-20. The overhead forecast is outlined in Table 43.

**Table 43: Forecast overheads for Ergon Energy regulated services**

Overhead forecast	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
<b>RIN reported operating expenditure less FIT</b>	<b>352.24</b>						
Base year direct costs	237.32						
SCS operating expenditure overhead	114.92						
Overhead applied to other non-SCS operating expenditure activities	288.46						
<b>Base year overhead costs</b>	<b>403.38</b>	<b>366.26</b>	<b>365.56</b>	<b>378.52</b>	<b>390.08</b>	<b>398.69</b>	<b>408.12</b>
Accounting adjustments	(0.71)						
CAM adjustments	(4.35)						
<b>Adjusted base year operating expenditure</b>	<b>398.33</b>	<b>366.26</b>	<b>365.56</b>	<b>378.52</b>	<b>390.08</b>	<b>398.69</b>	<b>408.12</b>
<i>Classification changes</i>							
Adjustment for future efficiencies	(32.06)	0.00	(2.54)	(2.60)	(2.62)	(2.65)	(2.67)
Output growth		5.42	5.54	6.22	5.78	5.80	5.89
<i>Step changes and bottom up</i>							
Asset service fee	0.00	(6.12)	4.96	7.95	5.45	6.28	5.02
IT and communications costs			5.00				

Overhead forecast	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
<b>Overheads before escalation (\$2013-14)</b>	<b>366.26</b>	<b>365.56</b>	<b>378.52</b>	<b>390.08</b>	<b>398.69</b>	<b>408.12</b>	<b>416.36</b>
2012-13 de-escalation amount	(10.67)	(11.36)	(12.62)	(14.27)	(15.94)	(17.94)	(19.98)
<b>Total overhead forecast (\$2012-13)</b>	<b>355.60</b>	<b>354.20</b>	<b>365.90</b>	<b>375.81</b>	<b>382.75</b>	<b>390.18</b>	<b>396.39</b>
Real price growth - overheads only			25.96	35.57	45.64	57.28	70.73
<b>Total overhead forecast (\$2014-15)</b>		<b>354.20</b>	<b>391.86</b>	<b>411.38</b>	<b>428.39</b>	<b>447.46</b>	<b>467.12</b>

Ergon Energy's CAM sets out how the Ergon Energy Group attributes costs to, or allocates costs between, the regulated distribution services and unregulated services provided by the Ergon Energy Group. Ergon Energy applies our CAM to prepare forecast operating expenditure to be submitted to the AER in accordance with clause 6.5.6 of the NER.

For overhead costs, we allocate the overheads to Standard Control Services operating expenditure using the CAM process. This allocation is shown in Figure 12.

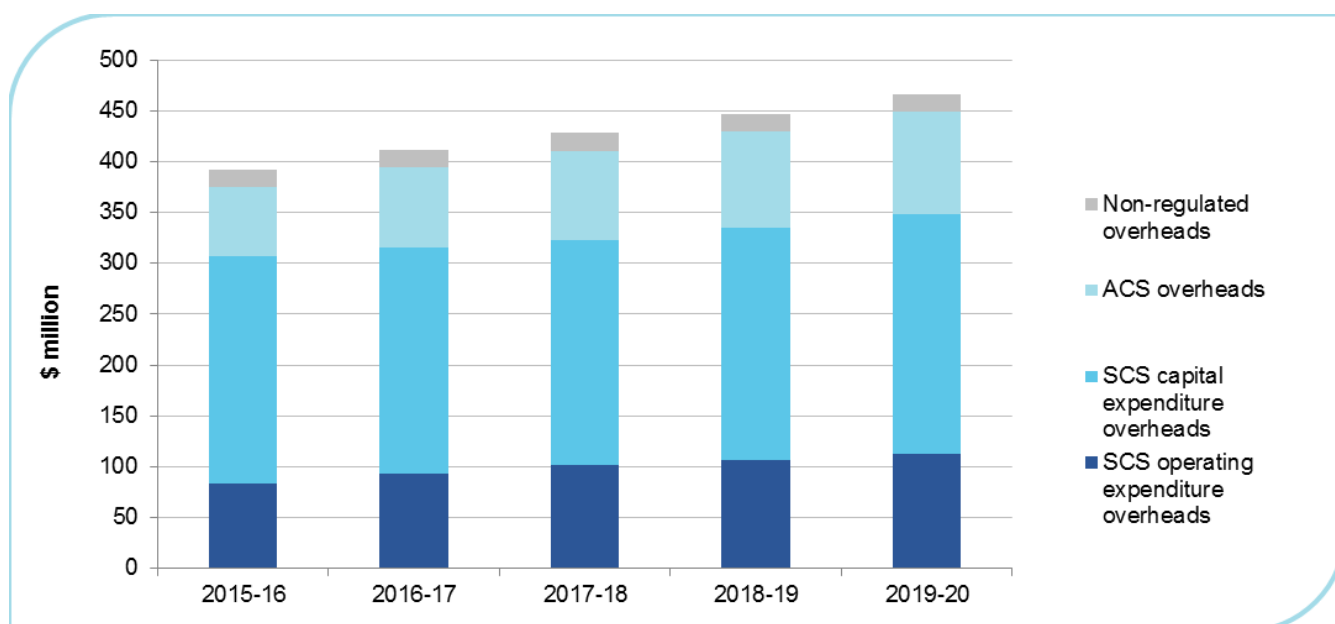


Figure 12: Allocation of forecast overheads to service categories

## 5.4 Other Issues

### Debt raising costs

Ergon Energy is proposing a debt raising allowance to compensate for the transactional costs that a prudent service provider acting efficiently incurs while raising debt. Ergon Energy engaged Incenta Economic Consulting (Incenta) to undertake an independent review of the benchmark efficient costs for Ergon Energy, recognising the development of regulatory recognition of debt raising costs and its components.

Further information summarising Incenta's findings can be found in Section 2.9 of our *Opex Forecast Summary* document. The full Incenta Economic Consulting Report can be found in our supporting document *06.02.04 – Ergon Energy Debt Transaction Costs 30 June 2014*.

The Distribution Network Pricing Arrangements Rule change<sup>98</sup> imposes a regulatory constraint on Ergon Energy requiring debt financing to be completed by 28 February each year to enable pricing proposals to be submitted to the AER earlier than is currently required. By extension, this requires Ergon Energy to refinance debt at least four months prior to the commencement of the next regulatory year.

In these circumstances, Standard & Poor's requirement to refinance debt three months ahead cannot be met, as the regulatory framework will actually require DNSPs to refinance debt four months ahead. If this occurs, the estimate for early issuance costs provided above should be recalculated based on a four months ahead refinancing period instead of three months ahead.

### **Demand Management Innovation Allowance**

The DMIA represents expenditure related to activities undertaken in accordance with the innovation allowance provided by the AER under the DMIS.

Costs recovered under the DMIA:

- must not be recoverable under any other jurisdictional incentive scheme
- must not be recoverable under any other state or Commonwealth Government scheme
- must not be included in forecast capital or operating expenditure approved in the distribution determination for the regulatory control period under which the scheme applies, or under any other incentive scheme in that determination.

For revenue modelling purposes, Ergon Energy has included the \$5 million DMIA (in real \$2014-15) as a revenue adjustment and we have adjusted our base year operating expenditure accordingly.

## **6 Outcomes for customers**

The BST outcomes for Ergon Energy's Standard Control Services are depicted in Figure 13 below.<sup>99</sup>

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<sup>98</sup> AEMC (2014), *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014.

<sup>99</sup> This represents the adjusted forecast following allocation of overheads in accordance with the CAM.

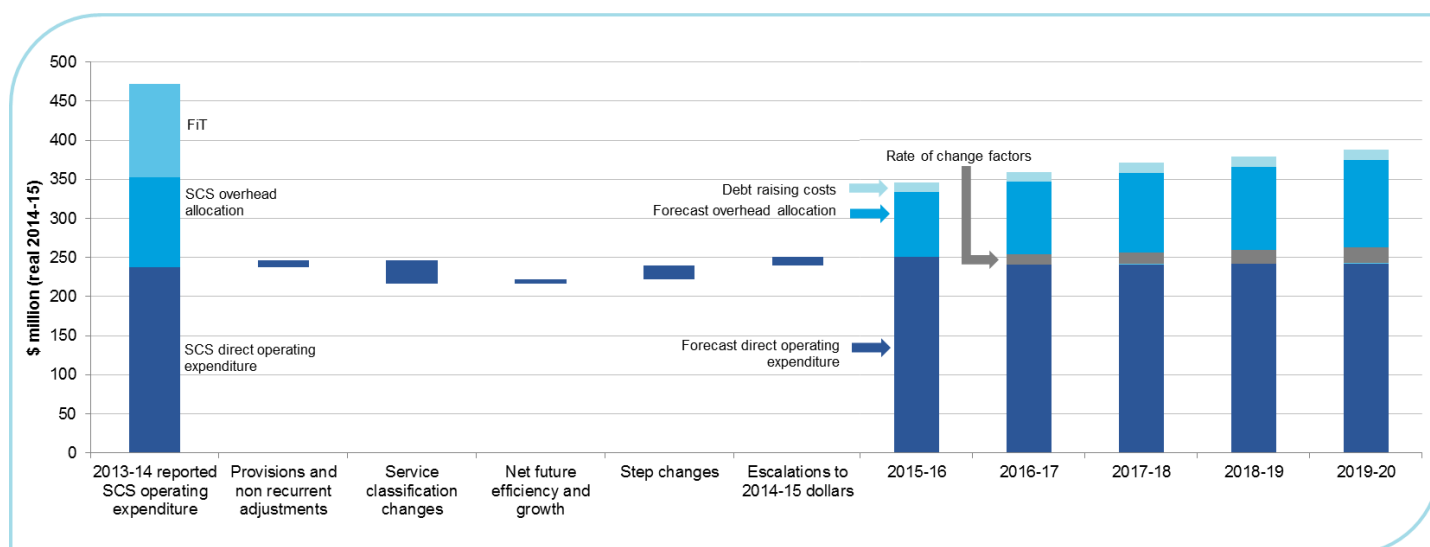


Figure 13: BST outcomes

## 7 Responding to the AER’s Benchmarking Report and subsequent determinations

### 7.1 Expenditure Forecast Assessment Guideline

The AER’s Expenditure Forecast Assessment Guideline sets out how the AER expects to assess a business’ Regulatory Proposal and how it determines a substitute forecast when required. The AER’s Guideline is not binding and must be departed from (with reason) if it will result in a decision or outcome inconsistent with the NER or the NEL.

At the time of our October Regulatory Proposal, we asked Huegin Consulting to consider the AER’s Expenditure Forecast Assessment Guideline and assist us in whether the basis of our methodology and inputs would be consistent with a reasonable assessment of the forecasts consistent with the Guideline.

Huegin’s report<sup>100</sup> noted significant limitations with the AER’s models and underlying data. It recommended that low weight should be given to these techniques when determining the reasonableness of a forecast or substituting for another forecast.

Their conclusions, when considering Ergon Energy’s approach in the context of the Guideline are as follows:

“The Ergon Energy assumption of productivity improvement in their base-step-trend model for future opex lies within the range of outcomes possible from the economic benchmarking. Whilst this is not a basis to accept the Ergon Energy assumption, given the limitations of the modelling

<sup>100</sup> Huegin (2014), *Productivity change in the context of the AER Guideline*. Refer to 06.01.03 – Huegin Productivity Analysis.

outlined in this report, there is certainly no basis to reject the assumption based on the modelling techniques within the AER's Expenditure Forecast Assessment Guideline."<sup>101</sup>

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## 7.2 Our response to the AER's Preliminary Determination

Since we submitted our October Regulatory Proposal, the AER has released its benchmarking report and also made several draft and final determinations. We note in our submission to the AER's Preliminary Determination that we responded to a number of these processes as we saw the AER's application of new decision-making powers for the first time. Ergon Energy, like a number of NSPs, became increasingly concerned with the approach the AER was taking.

While the AER has made some changes to its approach, Ergon Energy is still of the view that the AER has not applied itself properly to the task of assessing our forecast operating expenditure. We have included a number of expert reports which attest to this in support of our submission to the AER's Preliminary Determination.

Ergon Energy has made some adjustments to our forecasts to reflect the AER's approach to calculating operating expenditure forecasts, and we have accepted some elements of the AER's decision in our revisions. Ergon Energy has also considered our forecasting approach and where necessary, fine-tuned it to make it easier to understand in the context of the AER's own assessment process.

Notwithstanding these changes, we remain opposed to the AER's assessment and substitution framework as they are likely to lead to skewed results that will not be in the long-term interests of consumers.

We have provided more detail in our submission in response to the AER's Preliminary Determination, particularly in *Opex (Base Year) – Response*.

## 8 Meeting Rule requirements

The NER places obligations on Ergon Energy to provide information to assist the AER make a decision on the total operating expenditure for the period. We believe there is sufficient evidence in this Regulatory Proposal and supporting documents to satisfy the AER that our proposed operating expenditure reflects the operating expenditure criteria, subject to final adjustment of escalation factors and debt raising costs closer to the time of the Distribution Determination.

Our supporting document *06.01.05 – (Revised) Meeting Rule Requirements for Expenditure Forecasts* provides substantial detail on:

- why the forecasts enable Ergon Energy to achieve each of the operating expenditure objectives
- why Ergon Energy believes there is sufficient evidence to satisfy the AER that the forecasts meet the operating expenditure criteria.

The approach outlined in *06.01.05 – (Revised) Meeting Rule Requirements for Expenditure Forecasts* remains applicable to this revised Regulatory Proposal. Where applicable or necessary, Ergon Energy has supplied updated information regarding any material changes to our forecasts

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<sup>101</sup> *06.01.03 – Huegin Productivity Analysis*, p13.



and the application of the relevant NER requirements in the attachments that support this revised Regulatory Proposal.

## 8.1 Plans, policies and strategies

We have in place a suite of proven and well established plans, policies and strategies which are used to guide and support the business' daily operations. These documents have been relied upon in the development of this Regulatory Proposal and associated expenditure forecasts.

We firmly believe that, taken together, these documents support the development of operating expenditure forecasts that will achieve all of the operating expenditure objectives in the regulatory control period 2015-20. This is because these plans, policies and strategies ensure that our operating expenditure forecasts have regard for the:

- number, age and condition of each class of distribution asset that is needed to deliver our Standard Control Services
- need to comply with relevant regulatory obligations
- service standards that we must deliver.

Our supporting document *07.09.17 – Our Capital Governance and our plans, policies and procedures* outlines Ergon Energy's framework for the development and prioritisation of our capital and operational expenditure investment program to meet the expenditure objectives, criteria and factors set out in the NER, supported by a hierarchy of governance bodies and approval authorities and various overarching strategies and management plans. This is complemented with additional information from the following supporting documents:

- *01.01.01 – (Revised) Legislative and Regulatory Obligations and Policy Requirements*
- response to the RIN, Templates 7.1 and 7.3.

## 9 Supporting information

The following documents referenced in this appendix accompany our Regulatory Proposal:

Name	Ref	File name
(Revised) Ergon Energy's Journey to the Best Possible Price	0A.01.02	(Revised) Best Possible Price
Informing our plans, Our Engagement Program	0A.01.04	Engagement Program
(Revised) Legislative and Regulatory Obligations and Policy Requirements	01.01.01	(Revised) Legislative and Regulatory obligations
(Revised) Operating Forecast Expenditure Summary Document	06.01.01	(Revised) Opex forecast summary
(Revised) Step Changes for Operating Costs	06.01.04	(Revised) Step changes
Huegin Productivity Analysis	06.01.03	Ergon Opex Productivity Analysis
(Revised) Meeting Rule Requirements for Expenditure Forecasts	06.01.05	(Revised) Meeting the Rules requirements
Certification of reasonableness – expenditure forecast assumptions	06.01.06	Certification of reasonableness – expenditure forecast assumptions
(Revised) System related operating expenditure summary	06.01.02	(Revised) System related operating expenditure summary

Name	Ref	File name
Jacobs: Cost Escalation Factors 2015-20	06.02.02	Cost Escalation Factors 2015-20 SKM
Ergon Energy Debt Transaction Costs 30 June 2014	06.02.04	Incenta Report Debt Transaction Costs
Jacobs: Addendum Cost Escalation Factors 2015-20	06.02.07	Jacobs Addendum Cost Escalation Factors 2015-20
Our Capital Governance and our plans, policies and procedures	07.09.17	Governance, Plans, Policies and Procedures
Opex (Base Year) – Response	N/A	Ergon Energy – Opex (Base Year) – Response

# Appendix B:

## Capital expenditure forecasts for Standard Control Services

### Introduction and summary of changes

Our capital expenditure forecasts are focused on continuing to give our customers a safe, dependable service, and increasingly greater choice and control as our industry and the marketplace evolves. Our challenge is to deliver this while taking the pressure off electricity prices.

In considering our investment plans, we have looked at our cost drivers and the other challenges our people face in meeting our customers' expectations – both those that are unique to Ergon Energy and common to the industry.

Due to a very different growth profile to what was forecast at the time of the last distribution determination, and the low growth economic scenario we are using for our forward planning, our capital expenditure will be lower in 2015-20 – totalling \$3.4 billion.

### Customer benefits

Our capital expenditure program is critical to delivering on our service commitments to regional Queensland – most importantly to our safety and reliability commitments. It is also core to our disaster management and storm/outage response capability and to evolving the network to best support customer choice in economic electricity supply solutions.

Our goal for our safety performance is to stand with the best in our industry... to always be SAFE.

We'll maintain recent overall improvements in power supply reliability... and continue to improve the experience of customers who are suffering outages well outside our standards.

Getting our new connection forecasts right is also vital to us playing our part in powering economic growth – and making it easier to connect to the network.

## Appendix B: Capital expenditure forecasts for Standard Control Services

### 1 Overview

Our total proposed capital expenditure for the regulatory control period 2015-20 is lower than the actual capital expenditure we expect to incur in the regulatory control period 2010-15 and lower than our October Regulatory Proposal. The total capital expenditure Ergon Energy requires to meet the capital expenditure objectives in the regulatory control period 2015-20 is provided below.

Table 44: Forecast capital expenditure, 2015-20<sup>102</sup>

\$'000 (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Capital expenditure	779,006	716,381	666,324	643,423	636,128	3,441,260

This appendix outlines:

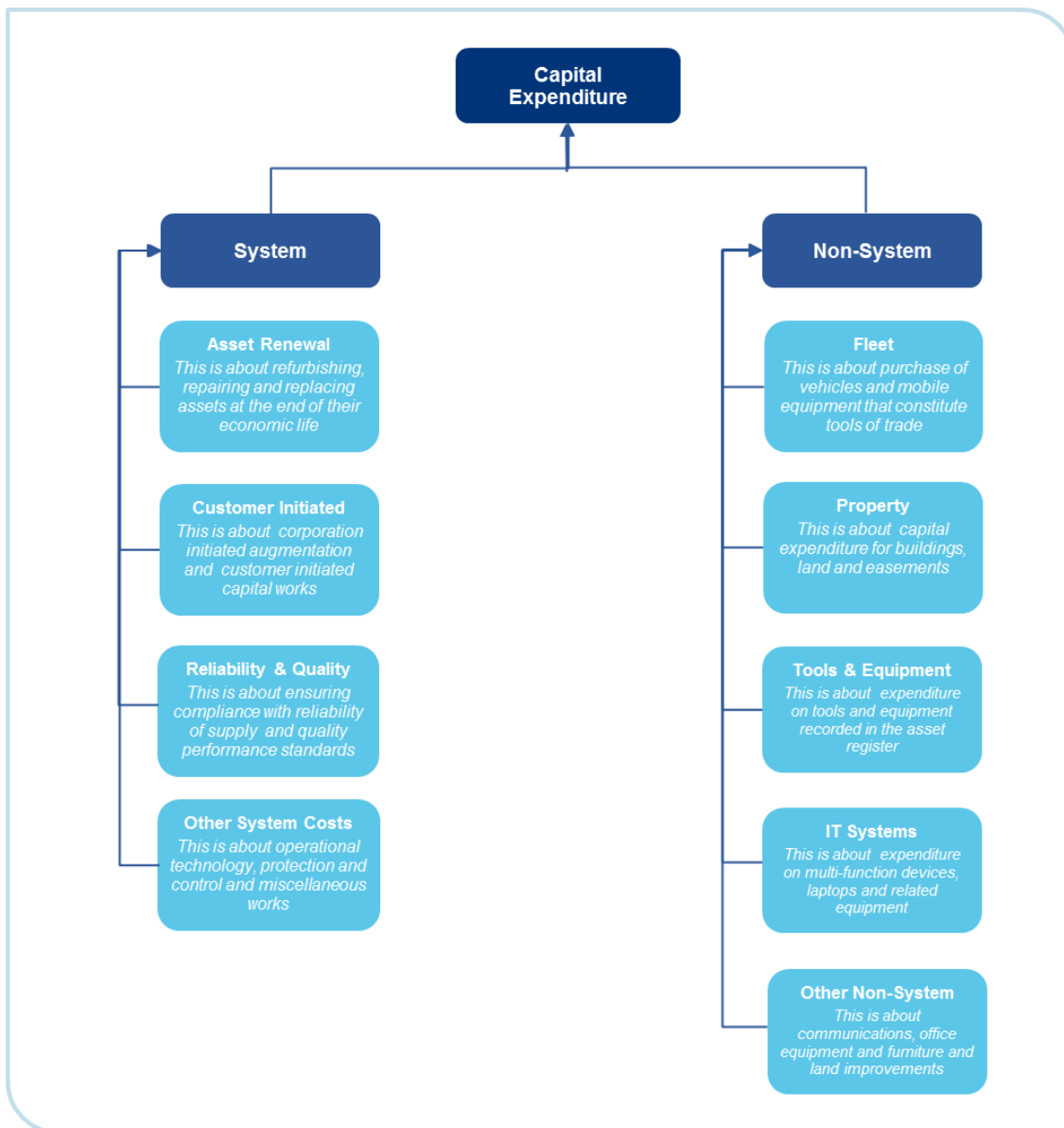
- why Ergon Energy incurs this level of capital expenditure, and the various categories of expenditure that make up Ergon Energy's capital program
- our level of capital expenditure in the regulatory control period 2010-15 and how it compares to the efficient level of capital expenditure set by the AER for that period
- factors influencing our capital expenditure in the regulatory control period 2015-20, including the move to new security criteria
- our methodology, approach and assumptions underpinning our forecasts
- outcomes for customers as a result of our forecasts
- how our capital expenditure forecasts satisfy the capital expenditure criteria, having regard to the factors outlined in the NER.

Appendix E separately details our proposal in relation to the need for the AER to apply a transition path in the scenario where the AER rejects our proposal and substitutes it with a much lower forecast.

### 2 Components of our capital expenditure requirement

We distinguish between two types of capital expenditure – system and non-system capital expenditure. The components of each one are illustrated in Figure 14 and discussed further below.

<sup>102</sup> Reflects the total gross capital expenditure for Standard Control Services, including customer contributions related to connection services classified as standard control (small customer connections).



**Figure 14: Components of our capital expenditure requirement**

**Asset Renewal capital expenditure** is recurrent, non-demand driven capital expenditure. It arises from the need to maintain Ergon Energy’s distribution asset base in order to continue efficiently delivering our service performance, and to maintain the reliability and quality of supply required by technical standards. Asset Renewal capital expenditure therefore involves refurbishing, repairing and replacing asset components that reach the end of their economic lives, as determined by their age, condition, technology or environment. This capital expenditure involves both proactive and reactive work. Our *Asset Renewal Expenditure Forecast Summary* supporting document<sup>103</sup> is an important reference document which explains this category of expenditure in more detail.

**Corporation Initiated Augmentation (CIA) capital expenditure** is expenditure that is required to augment or reinforce capacity on our shared subtransmission and distribution network in response to increased customer demand. Without this expenditure, or non-network alternatives, we can

<sup>103</sup> 07.00.01 – (Revised) Asset Renewal Expenditure Forecast Summary.

exceed our network's existing capacity and fail to comply with our security of supply requirements, MSS and requirements of the NER and *Electricity Act 1994 (Qld)*. Our *CIA Expenditure Forecast Summary* supporting document<sup>104</sup> is an important reference document which explains this category of expenditure in more detail.

**Customer Connection Initiated Capital Works** relates to works to service new or upgraded customer connections requested by our customers. We have a legislative obligation, as far as is technically and economically practicable, to connect customers to our distribution network. This expenditure involves work that is to be undertaken by us, someone acting on our behalf or by real estate developers or other service providers, where the assets are subsequently gifted to Ergon Energy. Our *Customer Connection Initiated Capital Works Expenditure Forecast Summary* supporting document<sup>105</sup> is an important reference document which explains this category of expenditure in more detail.

**Reliability and Quality of Supply capital expenditure** involves two parts. Our reliability capital expenditure relates to works directly targeted at addressing reliability of supply issues in order to meet mandated reliability obligations and to improve the performance experienced by customers supplied by a consistently poor performing feeder or feeder section. Our quality improvement capital expenditure relates to works to comply with mandatory quality of supply obligations in accordance with existing statutory requirements and future regulatory performance standards and targets. Our *Reliability and Quality of Supply Expenditure Forecast Summary* supporting document<sup>106</sup> is an important reference document which explains this category of expenditure in more detail.

**Other System capital expenditure** encompasses capital expenditure that does not conventionally align to the above capital expenditure categories and their drivers. We break our other system capital expenditure down into the three sub-categories: operational technology; protection and control; and miscellaneous works. Our *Other System and Enabling Technologies Expenditure Forecast Summary* supporting document<sup>107</sup> is an important reference document which explains this category of expenditure in more detail.

Our non-system capital expenditure comprises the following categories:

- **Fleet capital expenditure** – purchases of vehicles and mobile equipment that constitute tools of trade (refer to our *Fleet Expenditure Forecast Summary* supporting document<sup>108</sup>)
- **IT System capital expenditure** – expenditure on multi-function devices, laptops and related equipment that are not provided by SPARQ (refer to our *ICT Expenditure Forecast Summary* supporting document<sup>109</sup>)
- **Property capital expenditure** – non-system capital expenditure for buildings, land and easements (refer to our *Property Expenditure Forecast Summary* supporting document<sup>110</sup>).

Separate to these categories of expenditure are purchases of tools and equipment necessary for providing Standard Control Services that are over \$1,000 and are recorded in the asset register in

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<sup>104</sup> 07.00.02 – (Revised) Ergon Energy CIA Expenditure Forecast Summary.

<sup>105</sup> 07.00.03 – (Revised) Ergon Energy Customer Connection Initiated Capital Works Expenditure Forecast Summary.

<sup>106</sup> 07.00.05 – (Revised) Ergon Energy Reliability and Quality of Supply Expenditure Forecast Summary.

<sup>107</sup> 07.00.04 – (Revised) Ergon Energy Other System and Enabling Technologies Expenditure Forecast Summary.

<sup>108</sup> 07.00.06 – (Revised) Ergon Energy Fleet Expenditure Forecast Summary.

<sup>109</sup> 07.00.07 – (Revised) Ergon Energy ICT Expenditure Forecast Summary.

<sup>110</sup> 07.00.08 – Ergon Energy Property Expenditure Forecast Summary.

the categories of tools and ladders. Expenditure on communications, office equipment and furniture as well as land improvements which are not allocated to a specific category of expenditure are also included in the overall forecast.

Table 45 provides Ergon Energy's forecast capital expenditure for each year of the regulatory control period 2015-20, disaggregated by program of expenditure.

**Table 45: Proposed capital expenditure, 2015-20**

<b>\$'000 (real 2014-15)</b>	<b>2015-16</b>	<b>2016-17</b>	<b>2017-18</b>	<b>2018-19</b>	<b>2019-20</b>	<b>Total</b>
Asset Renewal	305,512	289,124	253,566	278,571	277,071	1,403,845
Corporation Initiated Augmentation	166,167	169,345	170,606	125,573	128,922	760,613
Customer Connection Initiated Capital Works	216,795	227,608	238,744	246,730	253,990	1,183,868
Reliability and Quality of Supply	3,133	3,235	3,317	3,347	3,365	16,396
Other System	40,966	29,994	19,192	26,714	23,679	140,544
Non-System	144,433	101,095	91,179	77,618	68,641	482,965
<b>Gross capital expenditure</b>	<b>877,006</b>	<b>820,401</b>	<b>776,604</b>	<b>758,553</b>	<b>755,668</b>	<b>3,988,230</b>
<i>less Alternative Control Services customer contributions</i>	<i>(98,000)</i>	<i>(104,020)</i>	<i>(110,280)</i>	<i>(115,130)</i>	<i>(119,540)</i>	<i>(546,970)</i>
<b>Standard Control Services gross capital expenditure</b>	<b>779,006</b>	<b>716,381</b>	<b>666,324</b>	<b>643,423</b>	<b>636,128</b>	<b>3,441,260</b>
<i>less Standard Control Services customer contributions</i>	<i>(29,620)</i>	<i>(30,810)</i>	<i>(32,030)</i>	<i>(32,820)</i>	<i>(33,520)</i>	<i>(158,800)</i>
<b>Standard Control Services net capital expenditure</b>	<b>749,386</b>	<b>685,571</b>	<b>634,294</b>	<b>610,603</b>	<b>602,608</b>	<b>3,282,460</b>

Note the forecast annual capital expenditures have been adjusted to reflect the following:

- some of the Standard Control Service non-system assets are also used in the provision of services other than Standard Control Services
- Customer Connection Initiated Capital Works includes customer contributed assets, which provide Standard Control Services (once commissioned and energised). Contributed assets may be in the form of:
  - cash or gifted assets arising out of connection services classified as Standard Control Services (such as small customer connections)
  - assets gifted to or constructed by Ergon Energy relating to connection services classified as Alternative Control Services (such as major customer and real estate development connections).

The 'net capital expenditure' above reflects our forecast of capital expenditure that is not otherwise funded through customer contributions, and is therefore required to be funded through our revenue cap and DUOS charges.

Table 46 shows that our total net capital expenditure over the regulatory control period 2015-20 is expected to be 3.37% lower than our October Regulatory Proposal.

**Table 46: Comparison between October and revised Regulatory Proposals, capital expenditure, 2015-20**

<b>\$'000 (real 2014-15)</b>	<b>October Regulatory Proposal</b>	<b>Revised Regulatory Proposal</b>	<b>% difference</b>
Asset Renewal	1,358,064	1,403,845	3.37%
Corporation Initiated Augmentation	790,490	760,613	(3.78%)
Customer Connection Initiated Capital Works	1,188,935	1,183,868	(0.43%)
Reliability and Quality of Supply	17,528	16,396	(6.46%)
Other System	148,872	140,544	(5.59%)
Non-System	603,341	482,965	(19.95%)
<b>Gross capital expenditure</b>	<b>4,107,231</b>	<b>3,988,230</b>	<b>(2.90%)</b>
<i>less</i> Alternative Control Services customer contributions	(551,940)	(546,970)	(0.90%)
<b>Standard Control Services gross capital expenditure</b>	<b>3,555,291</b>	<b>3,441,260</b>	<b>(3.21%)</b>
<i>less</i> Standard Control Services customer contributions	(158,260)	(158,800)	0.34%
<b>Standard Control Services net capital expenditure</b>	<b>3,397,031</b>	<b>3,282,460</b>	<b>(3.37%)</b>

## 2.1 Summaries of our expenditure by category

Our Regulatory Proposal suite includes a series of summary documents which provide sufficient detail around the basis of the forecasts for each capital expenditure category. We also provide further supporting evidence to meet the necessary requirements under the NER. Figure 15 below outlines the relationship between this appendix and other supporting documentation.

The remainder of this appendix covers expenditure at the total level.



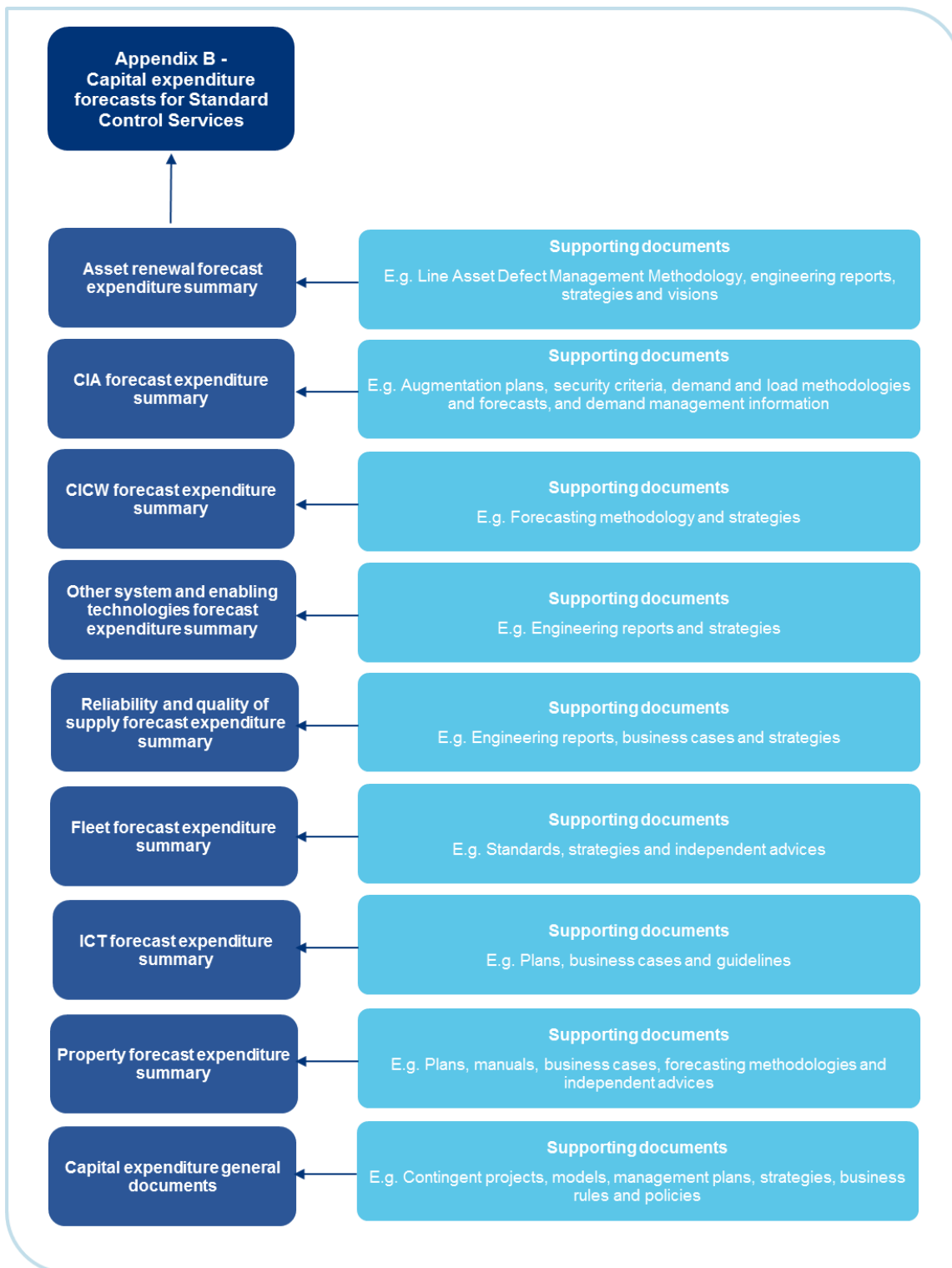


Figure 15: Capital expenditure documentation suite

### 3 Prior period performance

Table 47 and Table 48 provide Ergon Energy's actual expenditure for each year of the previous two regulatory control periods, disaggregated by program of expenditure.<sup>111</sup>

For comparison purposes, we have categorised this information in the same way as the capital expenditure forecast set out in Table 45. Information provided for both regulatory control periods are based on the CAM applying in the regulatory control period 2010-15.

**Table 47: Capital expenditure by category, 2005-10<sup>112</sup>**

\$'000 (real 2014-15)	2005-06	2006-07	2007-08	2008-09	2009-10	Total
Asset Renewal	202,072	169,549	126,560	147,830	159,968	805,979
Corporation Initiated Augmentation	149,886	218,522	293,104	290,949	222,628	1,175,088
Customer Connection Initiated Capital Works	249,460	349,158	331,307	323,686	270,155	1,523,766
Reliability and Quality of Supply	8,797	13,225	16,076	9,467	12,452	60,017
Other System	24,823	13,359	33,491	56,320	22,659	150,653
Non-System	186,312	169,571	143,591	106,764	102,286	708,526
<b>Gross capital expenditure</b>	<b>821,350</b>	<b>933,384</b>	<b>944,129</b>	<b>935,016</b>	<b>790,148</b>	<b>4,424,028</b>
<i>less Alternative Control Services customer contributions</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0</i>	<i>0</i>
<b>Standard Control Services gross capital expenditure</b>	<b>821,350</b>	<b>933,384</b>	<b>944,129</b>	<b>935,016</b>	<b>790,148</b>	<b>4,424,028</b>
<i>less Standard Control Services customer contributions</i>	<i>(45,692)</i>	<i>(51,887)</i>	<i>(83,333)</i>	<i>(107,879)</i>	<i>(67,290)</i>	<i>(356,080)</i>
<b>Standard Control Services net capital expenditure</b>	<b>775,659</b>	<b>881,497</b>	<b>860,796</b>	<b>827,137</b>	<b>722,859</b>	<b>4,067,948</b>

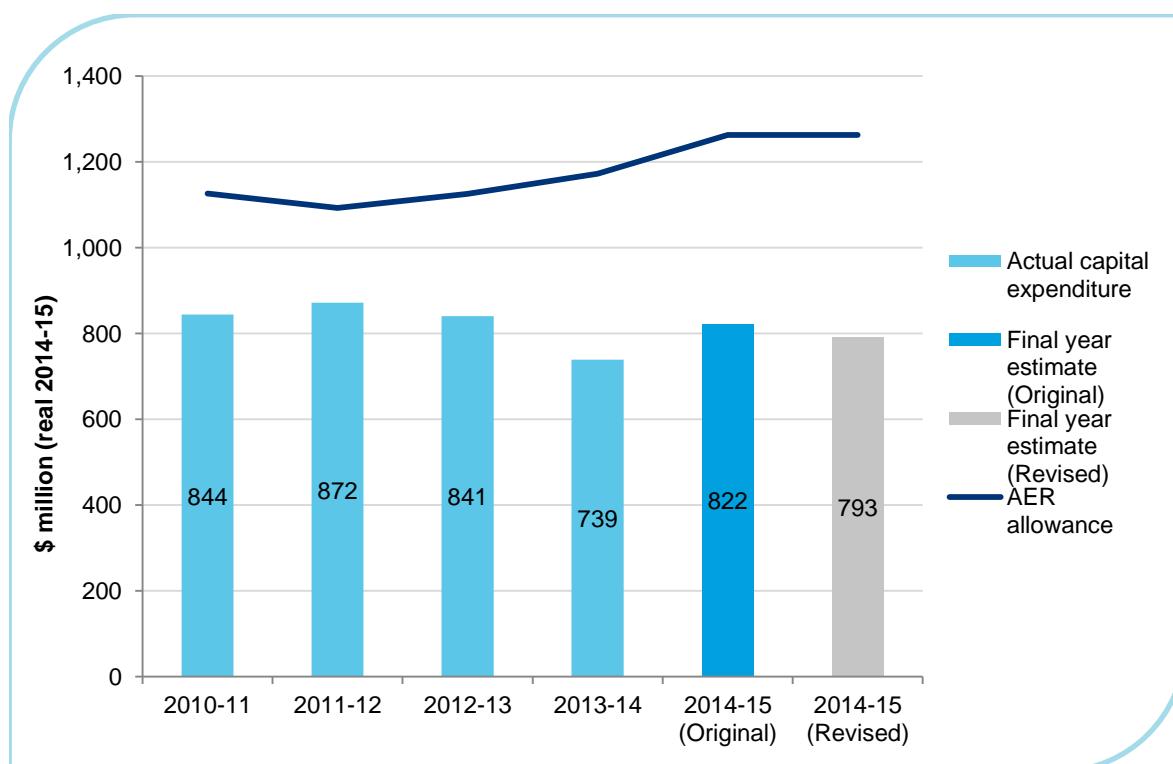
<sup>111</sup> NER, S6.1.1(6).

<sup>112</sup> Figures may not directly reconcile to figures set out in supporting documents due to differences in source data and assumptions.

**Table 48: Capital expenditure by category, 2010-15**

\$'000 (real 2014-15)	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Asset Renewal	228,371	266,667	289,671	229,834	281,047	1,295,590
Corporation Initiated Augmentation	148,225	175,096	152,173	165,888	146,671	788,054
Customer Connection Initiated Capital Works	204,234	197,787	209,593	207,267	159,499	978,381
Reliability and Quality of Supply	22,327	28,275	24,577	32,868	53,545	161,592
Other System	84,657	56,464	37,934	35,932	45,356	260,344
Non-System	156,394	149,502	135,604	95,125	124,965	661,590
<b>Gross capital expenditure</b>	<b>844,208</b>	<b>873,792</b>	<b>849,552</b>	<b>766,915</b>	<b>811,083</b>	<b>4,145,551</b>
less Alternative Control Services customer contributions	0	(2,248)	(8,914)	(27,729)	(17,950)	(56,841)
<b>Standard Control Services gross capital expenditure</b>	<b>844,208</b>	<b>871,544</b>	<b>840,638</b>	<b>739,187</b>	<b>793,133</b>	<b>4,088,710</b>
less Standard Control Services customer contributions	(75,854)	(59,023)	(71,117)	(61,340)	(58,720)	(326,053)
<b>Standard Control Services net capital expenditure</b>	<b>768,354</b>	<b>812,521</b>	<b>769,521</b>	<b>677,846</b>	<b>734,413</b>	<b>3,762,656</b>

Figure 16 compares Ergon Energy's actual and estimated capital expenditure for the regulatory control period 2010-15 with the AER's allowance for this period.



**Figure 16: Comparison of capital expenditure, 2010-15**

### 3.1 Expenditure outcomes in 2005-10

Our expenditure profile reflects that from early 2000 Ergon Energy was investing heavily in the network in response to population growth and in an effort to meet our customer's changing expectations around reliability and quality of supply; driven by the uptake of lifestyle appliances.<sup>113</sup> Additional network investment was required from 2004, to meet the higher reliability standards introduced in response to the Electricity Distribution Service Delivery (EDSD) Review.<sup>114</sup>

To achieve the higher reliability standards, each of the Queensland DNSPs had to undertake a number of measures. For Ergon Energy, this meant the obligation to achieve N-1 security on bulk supply substations and large zone substations (5MVA and above) and sub-transmission feeders. Steps also needed to be taken to improve network planning processes, improve maintenance programs and to better communicate with customers on network outages. While it was acknowledged by the EDSD Panel at the time that these recommendations would result in significant capital and operating expenditure, the impact of these reforms on price was not fully understood.

At the time of Ergon Energy's Regulatory Proposal for the regulatory control period 2010-15, the key drivers for Ergon Energy were expected to be continued growth in peak demand driven by economic and population growth in regional Queensland, continued investment to meet increasing reliability obligations and reasonable customer expectations for the safety, quality and reliability of their power supply. Further, our customers had just started to develop an interest in energy supply alternatives, both to procure and use electricity and the introduction of new government initiatives were unclear.

### 3.2 Expenditure outcomes in 2010-15

As outlined in earlier sections of this appendix, we expect our total capital expenditure for the regulatory control period 2010-15 to be considerably lower than the approved AER allowance.

This outcome has been driven by:

- our responsiveness to changing market and economic conditions to prudently avoid or defer unnecessary and costly capital investment in the network
- successful deferment of considerable network investment due to our demand management initiatives.

Our aim has been to ensure that our investment program did not further exacerbate affordability issues and to avoid incurring cost for work that was not required due to the lack of associated load or demand drivers.

We have also passed on to customers a series of network revenue reductions as a result of the 2011 Electricity Network Capital Program (ENCAP) Review, and absorbed costs associated with Cyclones Yasi, Oswald and Marcia.

During the regulatory control period 2010-15, Ergon Energy also worked closely with Energex and our Queensland Government shareholders to enable the distribution networks in Queensland to transition away from the deterministic EDSD Review N-1 security standards. This will help deliver

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<sup>113</sup> Ergon Energy (2007), *Annual Report 2006-07*, p19.

<sup>114</sup> Our supporting document 0A.01.02 – (Revised) *Ergon Energy's Journey to the Best Possible Price* provides further detail.

improved pricing outcomes for customers and reduce the level of network capital investment required in the long-term.

Non-network capital expenditure (especially in the areas of fleet and property) was also subject to significant scrutiny to ensure the levels of expenditure in these areas were kept to an absolute minimum level. Expenditure levels in these areas were reduced during the regulatory control period 2010-15 relative to the approved AER allowance, without compromising on safety, reliability or our ability to deliver services to our customers and to respond effectively to outages or weather driven disruption events.

Based on the latest available assessment of the impacts of the changes in our security and network planning criteria contained in our new Distribution Authority (effective from 1 July 2014) and our forward planning for non-network expenditure, we expect that our overall capital expenditure for this period will be approximately \$1.69 billion (real \$2014-15) less than the AER approved total capital expenditure allowance.

We have continued to position our expenditure in 2014-15 to ensure we deliver on our customer commitments for the regulatory control period 2010-15 and to deliver the best possible price outcome for the start of the regulatory control period 2015-20. Our expenditure profiles have shifted as we make efficient capital and operating expenditure trade-offs and update key project and program delivery milestones as we address priority investment needs and safety and compliance requirements.

Consistent with our gated governance investment framework, we have continually reviewed and scrutinised the quantum and timing of our future investment needs and priorities for the 2014-15 year. Investments were reviewed against a range of criteria including NER requirements, transitioning to our new security criteria, safety net and Value of Customer Reliability approach, significant weather events (e.g. Cyclone Marcia), safety, compliance and applicable external factors and market conditions.

The following parts of this Section 3 contain greater detail on our performance during the regulatory control period 2010-15 and the challenges we faced.

### **3.3 Changes to the external environment from 2010**

Within 12-18 months of the regulatory control period 2010-15 many of these drivers and assumptions had materially changed due to one or more of the following factors acting independently or collectively:

- weaker global economic conditions. While both Queensland and the rest of Australia have experienced slower economic growth in recent years, the moderation in growth has been more pronounced in Queensland.
- the effect of severe weather in 2010-11, which flooded mining operations, also had a specific effect in Queensland (and was not replicated in the rest of Australia).<sup>115</sup>
- the subsequent high Australian dollar dampened trade-exposed economic activity, particularly in the manufacturing sector.

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<sup>115</sup> Queensland Commission of Audit (2013), *Final Report – Volume 2*, February 2013, p5.

### 3.4 Affordability, customer concerns and how it resulted in reduced expenditure in the previous period

The full cost of the capital investment programs to address the EDSR recommendations was passed through to customers and this began to have a significant impact on network prices and, ultimately retail prices. This impact on network prices was greater than initially anticipated at the time the standards were introduced. Other policy changes such as the one-off effects of moving to the network plus retail (N+R) framework for setting regulated retail prices<sup>116</sup> and renewable energy policies (e.g. Solar Bonus Scheme) also contributed to higher electricity prices.

Climate change policies and subsidies for rooftop solar photovoltaic (PV) installations have led to a rapid increase in the number of households and businesses with solar PV. The installation of solar PV had a twofold effect on the network:

- It introduced an additional source of power for which, in the main, the networks were not designed for. This created immediate engineering, policy and regulatory issues.
- The pattern of solar generation is such that the peak demand has not significantly dropped, whereas overall consumption has. The net effect was that Ergon Energy was still investing in some parts of the network to cater for the peak, yet there was substantially less units of electricity being distributed.

Consumption patterns have therefore changed markedly since 2010, as a result of higher prices for electricity, the adoption of strategies to enhance energy efficiency and broad take-up of demand management initiatives. As customers have become more concerned about the cost of electricity they adopted measures to reduce usage. While these measures have resulted in an overall fall in consumption they have not necessarily resulted in reduced retail bills. Queensland households therefore became increasingly price sensitive as a result of substantial ongoing electricity price rises, seeking alternatives to consuming more energy which only lead to frustration as energy bills rose further to counter for global reductions in consumption.

In response to this, Ergon Energy realised that an immediate and proactive response was required to address the electricity affordability issue rather than wait until the end of the regulatory control period 2010-15.

In recognition of the cost pressures created by the higher reliability standards introduced following the EDSR Review, we investigated alternative methods for achieving security of supply on the distribution network that may be more cost effective and efficient in the long-term. Based on this work and our belief that greater flexibility was required to adapt to change and deliver value and choice to our customers, we commenced discussions with the Queensland Government and made submissions for a change in the policy settings.<sup>117</sup> The ENCAP Review ultimately recommended a relaxation of the security criteria (N-1) and changes to MSS which resulted in around \$709 million in capital expenditure reductions compared to the original AER allowance for 2010-15.<sup>118</sup>

In response to the ENCAP Review, Ergon Energy received a direction notice on 11 February 2012 from the Queensland Government to not recover the capital expenditure savings identified in the

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<sup>116</sup> Notified Prices for 2012-13 were the first set of retail tariffs that had been determined on the basis of the N+R methodology.

<sup>117</sup> Ergon Energy (2011), *Submission to the Electricity Network Capital Program Review – Somerville Review Panel*, 31 October.

<sup>118</sup> Ergon Energy identified capital savings totalling \$930 million over the regulatory control period 2010-15 although the total saving is offset by \$220 million in additional costs, resulting in a net saving of around \$709 million. Queensland Government (2011), *Electricity Network Capital Program Review 2011: Detailed report of the independent pane*, p73, [http://www.business.qld.gov.au/data/assets/pdf\\_file/0018/9117/ENCAP\\_Review\\_Final\\_Report\\_3\\_new.pdf](http://www.business.qld.gov.au/data/assets/pdf_file/0018/9117/ENCAP_Review_Final_Report_3_new.pdf).

ENCAP Review. As a result, Ergon Energy reduced our network charges by \$99.18 million in 2012-13 and 2013-14.

In May 2012, the Queensland Government established an Interdepartmental Committee on Electricity Sector Reform with a view to ensuring:

- electricity in Queensland is delivered in a cost-effective manner to customers
- Queensland has a viable, sustainable and competitive electricity industry
- electricity is delivered in a financially sustainable manner from the Queensland Government's perspective.

In response, we undertook an additional review of our program of works and further reduced our capital expenditure.

### 3.5 Our performance outcomes

#### Maximum (or peak) demand

Our maximum demand during the regulatory control period 2010-15 has remained steady – significantly less than either we or the AER anticipated. Figure 17 shows the trend in our monthly maximum demand since 2001 in total and across our northern, central and southern regions.

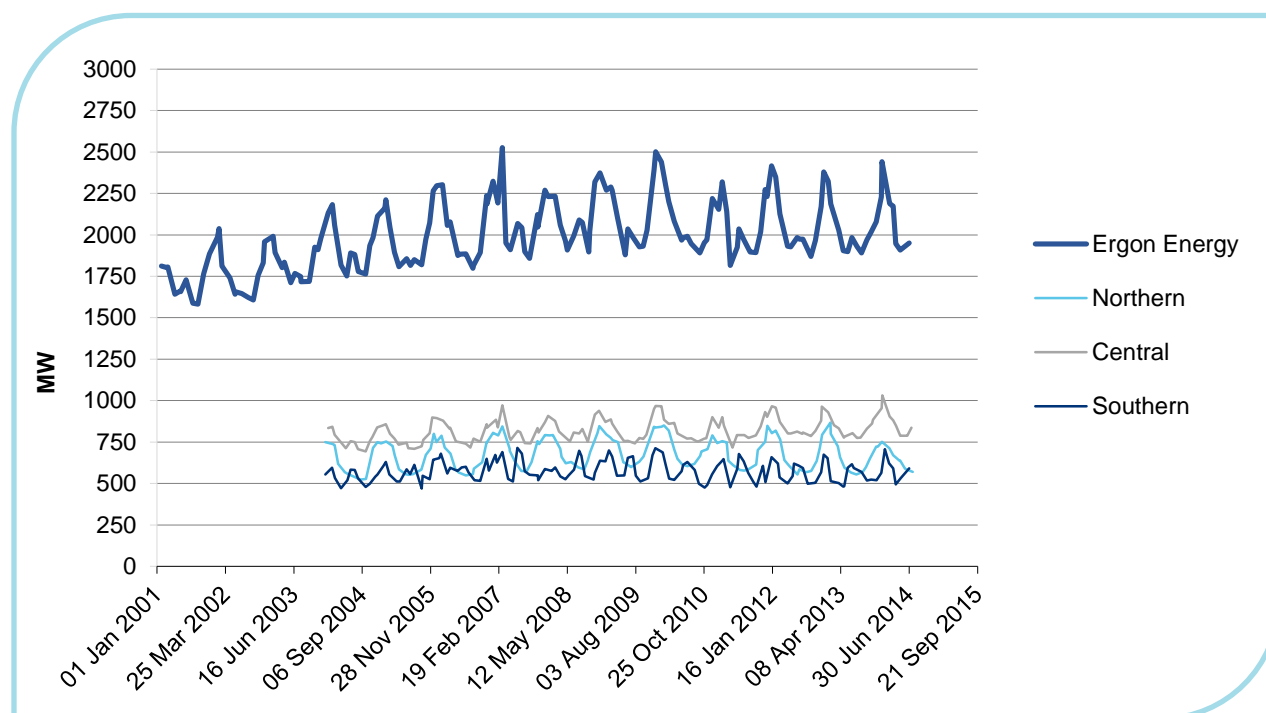


Figure 17: Monthly maximum demand

In the regulatory control period 2010-15, our aggregate maximum demand peaked in 2013-14 at 2,441MW. This represents a 5.3% increase on 2010-11 levels but a 3.4% decrease on 2008-09 levels, which was the peak of the previous regulatory control period. Due to a combination of factors, including the impact of the global financial crisis on the Queensland economy, the rate of growth in electricity demand slowed significantly over 2010 and 2011. Peak demand at this time was also impacted by cyclone events, milder summer temperatures and changes to energy consumption.



## Customer connection numbers

Table 49 shows that our customer connection numbers have increased by 1.62% per annum for the four years of the regulatory control period 2010-15 to date. Residential customer connections have increased on average by 1.41% per annum and non-residential customer connections have increased on average by 2.72% per annum.

**Table 49: Customer numbers, 2010-14**

	2010-11	2011-12	2012-13	2013-14
Residential customer numbers	577,958	585,538	595,439	607,276
Annual residential customer growth rate	1.24%	1.31%	1.69%	1.99%
Non-residential customer numbers	111,001	113,726	114,992	114,654
Annual non-residential customer growth rate	4.61%	2.45%	1.11%	(0.29%)
Total customer numbers	688,959	699,264	710,431	721,930
Annual growth rate	1.77%	1.50%	1.60%	1.62%

The actual average annual growth rate of 1.62% is slightly higher than our forecast annual total customer growth rate for the regulatory control period 2010-15 of 1.58%, which we detailed in our Regulatory Proposal for 2010-15.<sup>119</sup>

## Asset age

Our assets age at different rates, depending on their components, location, use, exposure to climatic conditions and history. While our average asset lives are within reasonable averages, we do face significant ongoing expenditure on assets that are approaching or have reached the limits of their viable lives.

## Reliability

Over the last five years the performance of the network has significantly improved. While weather conditions always play a part in reliability outcomes, this significant achievement is a result of a substantial investment in network improvements over the past decade, and the dedication of our people.

With the cost of electricity now such a significant issue for our customers, and given our improved performance, we no longer consider reliability improvement investment of this scale warranted. Our customers are now generally satisfied with the supply standards they receive.

We now see our challenge is to maintain reliability standards overall, while continuing to address areas of the network that are underperforming. Around 7% of our customers are supplied by sections of the network that are well outside the performance standards.

Our position also reflects changes to our Distribution Authority, which was modified in line with our customers' expectations in July 2014.

<sup>119</sup> Refer Table 39. Ergon Energy (2009), *Regulatory Proposal to the Australian Energy Regulator, Distribution services for period 1 July 2010 to 30 June 2015*, 1 July 2009, p150.



Up until 1 July 2014, the Queensland Electricity Industry Code set out the MSS levels that we must meet for our reliability performance.<sup>120</sup> These are expressed as annual limits for our urban, short rural and long rural feeders for the duration and frequency of interruptions (expressed as SAIDI and SAIFI).

Table 50 shows that we met five of our six MSS limits in 2010-11 to 2012-13, and all six MSS limits in 2013-14. In 2014-15, we are expecting to meet five of our six MSS limits, with the long rural SAIDI performance likely to exceed the limit as a result of an unusually active summer storm season across much of western Queensland. Specifically, over the 2014-15 summer storm season the long rural feeders were subjected to a significantly higher number of lightning strikes compared to the past five storm seasons, with 70 per cent more strikes in close proximity to long rural feeders compared to the historical average.

**Table 50: Reliability performance, 2010-15**

		2010-11	2011-12	2012-13	2013-14	2014-15 (estimate)
<b>SAIDI</b>						
Urban	MSS	149	148	147	146	149
	Actual	148.88	136.28	135.12	118.49	130.69
Short rural	MSS	424	418	412	406	424
	Actual	425.74	391.95	341.44	291.91	371.07
Long rural	MSS	964	948	932	916	964
	Actual	827.35	1,041.58	951.53	798.42	1,078.54
<b>SAIFI</b>						
Urban	MSS	1.98	1.96	1.94	1.92	1.98
	Actual	1.628	1.413	1.493	1.394	1.471
Short rural	MSS	3.95	3.9	3.85	3.8	3.95
	Actual	3.532	3.549	2.977	2.767	3.286
Long rural	MSS	7.4	7.3	7.2	7.1	7.4
	Actual	5.266	7.019	6.246	6.118	7.006

## Quality of supply

In the previous regulatory control period 2005-10, Ergon Energy initiated a strategic program of power quality monitoring device installations across the distribution network. The investment in this program continued into the regulatory control period 2010-15 and has to date resulted in the installation of 1,790 monitors across the network.

Consequently, 823 distribution feeders or approximately 67% of the network feeders are now monitored for Quality of Supply disturbances.

The customer outcomes resulting from the improved awareness and response to emerging issues can be demonstrated by the reduction in customer initiated quality of supply complaints received by Ergon Energy since the inception of this strategic program.

Table 51 below provides the annual network asset event records based on customer complaints that relate to quality of supply issues, and breaks this down to show the solar installation initiated

<sup>120</sup> The MSS levels are currently prescribed in our Distribution Authority.

complaints, and the non-solar installation related complaints received by Ergon Energy in the past five years. The early identification and proactive response provided to address emerging quality of supply problems is considered to have been a significant contributor to the improvement across the five-year period.

**Table 51: Quality of supply complaints, 2010-15**

Year	Quality of Supply complaints	Solar issue complaints	Non-solar complaints
2010-11	950	71	879
2011-12	975	147	828
2012-13	1,398	592	806
2013-14	817	307	510
2014-15 (estimate)	1,260	510	750

### **Our commitment to seeking alternatives to augmentation investment**

We reduced demand management through customer-side initiatives aimed at constrained areas of the network. In the regulatory control period 2010-15, we surpassed our five-year demand management target of 122MVA and are forecast to deliver 135MVA in demand reductions, deferring or avoiding \$664 million in capital investment.

### **Necessary emergency response for significant weather events**

A number of significant weather events affected expenditure in the regulatory control period 2010-15. Major restoration works were associated with Tropical Cyclones Yasi (2011), Anthony (2012), Oswald (2012), Ita (2014), Marcia (2015) and the flooding around the Bundaberg and Southern regions of Ergon Energy.

Over this period we have been investing in our network and people to uphold our commitment to “being there after the storm”. These initiatives include hardening the asset base (e.g. undergrounding assets, cost effective elevation of substations), developing advanced monitoring and real time data collection capabilities, and ensuring we have a strong on the ground emergency response and recovery/reconstitution capability. To better target our response, our people are also now supported by the Remote Observation Automated Modelling Economic Simulation technology, which can provide a rapid aerial damage assessment following a major event.

Not only did we respond to these significant weather events, but we did not seek to raise electricity prices as a result of the unforeseen costs we had to incur in responding to these events. Going forward, we are considering financial products to ensure our customers are not exposed to what could potentially be a significant price shock impact, if one or more of Queensland’s coastal population centres were devastated by a major cyclone.

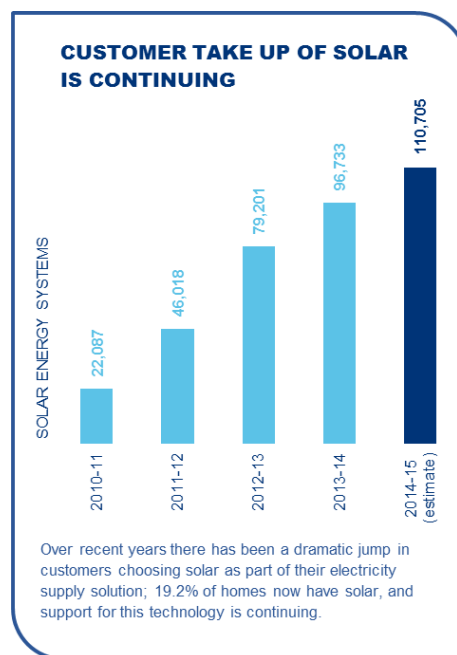
### **Necessary response to solar uptake**

By and large, today’s electricity network is currently geared to a one-way supply from the power station through the ‘poles and wires’ into the customer’s premise.

Increasing the amount of two-way supply, such as when a customer with solar energy feeds energy back into the grid, requires us to invest to modernise the distribution network, and to manage the growing volume of data involved efficiently.

More than one in five households now have solar and, despite declines in government incentives, our customers' intent to purchase or expand on their current solar energy system remains high. Solar energy exports, together with renewable energy from the sugar industry (bagasse) and other sources, are already contributing over 10% of the electricity for our main grid. Twenty-six per cent of Queenslanders have indicated they are looking to either purchase more panels or acquire solar PV in the next two years.

We have already begun to respond to these technical challenges by integrating operational technology with our more traditional network management capabilities in order to optimise business processes, enhance decision-making, reduce costs and lower risks.



## 4 Factors influencing forecasts in 2015-20

There are many factors influencing our capital expenditure forecast requirement for the regulatory control period 2015-20:

- our inherent network area, design, environment and customer base
- existing obligations, rules requirements, plans policies and procedures
- our current performance in key drivers of expenditure for each of our expenditure categories
- our commitments to customers based on our ongoing conversation on what they are looking for from Ergon Energy in the regulatory control period 2015-20.

### 4.1 Our inherent network area, design, environment and customer base

#### Our network area

Our distribution network covers 97% of the area of Queensland. Our focus is on customers who live in rural and regional Queensland. There are two specific features that set our distribution network apart from other DNSPs operating in the National Electricity Market (NEM). The first of these is the relatively large amount of sub-transmission network that Ergon Energy has had to build and manage. The second factor is the relatively large proportion of the network that is radial (rather than meshed) in design.

With such a large network area it is inevitable that we experience varying levels of customer density and must distribute electricity across large distances. This has clear implications for both the investment required per customer, and the way we operate. It can make network and non-network costs look higher than other distributors in areas like property and fleet, which are needed to access the assets (for emergency response, pole inspections and vegetation management etc.).

## Our network environment

Our network is built, maintained, operated and supported within an area that has a harsh environment and climate. Ergon Energy is seen to exhibit the highest temperature, largest annual rainfall and rainfall variability, as well as the third highest average relative humidity of the Australian DNSPs. We also have high bushfire risks for a large portion of our network area and are unique compared to DNSPs in the NEM with respect to our exposure to cyclones. Further, our network contains the areas that are subject to the most intense (from a wood pole degradation perspective) environment.

The variability of environmental effects within the network presents Ergon Energy with a set of challenges for efficient maintenance of physical assets. Specifically, when a broad range of conditions is to be considered, significant complexity is introduced for development of optimal maintenance schedules and resource allocation.

The climatic conditions while harsh for our network infrastructure can have positive outcomes for customers in the area of alternative energy sources. Queensland has had the greatest uptake of solar power in Australia. Over the period from 2006 to 2013, Ergon Energy experienced a relatively significant decrease in energy density, and the highest increase in peak demand, but (to a greater extent than other DNSPs) is in the position of still having to build, maintain, operate and support a growing peak demand because the overall demand density and energy delivered is increasing.

## Our network design

Our network design is also a significant outlier on many metrics, because of our network area. Ergon Energy has more overhead sub-transmission lines than any other Australian DNSP; this is because of the significant potential for voltage drop over the vast distances to be covered, and the boundaries of the Powerlink transmission network. We have the highest line capacity (KVA-kms) per customer and the second lowest percentage of underground network. Huegin's analysis of AER benchmarking data suggests Ergon Energy has a significant number of cost disadvantages, particularly at the inherent and inherited end of the cost driver.<sup>121</sup>

## Existing obligations, rules requirements, plans, policies and procedures

Our capital expenditure forecasts for the regulatory control period 2015-20 are developed by applying a series of plans, policies, procedures and strategies that, taken together, achieve the capital expenditure objectives in the NER.

This is because these plans, policies, procedures and strategies ensure that our capital expenditure forecasts have regard for:

- our and our customers' capital expenditure-related outcomes and goals
- our relevant regulatory obligations
- the service standards that we must deliver.

Our supporting document *07.09.17 – Our Capital Governance and our plans, policies and procedures* outlines Ergon Energy's framework for the development and prioritisation of our capital and operational expenditure investment program to meet the expenditure objectives, criteria and factors set out in the NER, supported by a hierarchy of governance bodies and approval authorities

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<sup>121</sup> 0A.02.01 – Ergon Energy Expenditure Benchmarking.

and various overarching strategies and management plans. This is complemented with additional information from the following supporting documents:

- *01.01.01 – (Revised) Legislative and Regulatory Obligations and Policy Requirements*
- response to the RIN, Templates 7.1 and 7.3.

## **4.2 Our commitment to customers based on what they told us**

The above factors in the regulatory control period 2010-15 have led to our service and price performance to customers. We have asked our customers what they are looking for in the regulatory control period 2015-20. Our commitment to what customers want, in addition to ensuring we can meet relevant requirements of the NER and other regulatory obligations, is largely driving the expenditure program in the regulatory control period 2015-20.

### **Peace of mind – being always safe**

Ergon Energy is committed to ensuring the safety of our customers, the community, employees and contractors. This will see an ongoing investment in control measures around potential life threatening risks, a focus on reducing dangerous electrical events. To maintain the safety (and reliability) of the network we have a significant asset refurbishment and replacement program, including an additional program to address a large volume of conductor clearance issues that have been identified since our October Regulatory Proposal was lodged. Over recent years we've gained a better understanding of the network and addressed significant issues. However, we have more work to do and have proposed a number of specific safety-related asset renewal programs in our Regulatory Proposal. We do not want to risk the network deteriorating unsafely, or safety problems to arise in the future.

We are also planning further investment in the protection and control equipment across our substations and distribution lines, in order to better ensure we adequately protect the community, our people, and the network itself from faults. This will include continuing to add sensitive earth fault protection to our high voltage feeder lines and addressing a safety issue associated with our older zone substations and how the auxiliary power is supplied for use in the substation itself.

The proposals around our operational technology investment will also support network operations in delivering positive safety outcomes.

In our Regulatory Proposal we are also seeking an allowance to help maintain high standards of environmental performance. We are continuing to progressively address transformer sites, which have been found to be without adequate oil containment protection, by installing oil separation and containment measures.

More detail on our renewal investment program can be found in *07.00.01 – (Revised) Asset Renewal Expenditure Forecast Summary*.

### **Peace of mind – reliability and quality of supply**

We have enhanced our demand forecasting, and governance protocols to be as prudent as possible in this area of investment in the network. We will seek to avoid the potential for network limitations that could impact security of supply, and ultimately reliability performance by using the most cost effective way to respond to constraints on the network. Increasingly this is through the use of non-traditional alternatives to system augmentation.

Our areas of Central and Southern Queensland service some of Queensland's largest energy users. Several of these resource companies are developing and proposing to develop LNG fields in the Darling Downs and west of Clermont, and demand is expected to be driven upwards as local service centres grow to supply accommodation and support industries. Port development is also expected to add considerable load.

At the substation level, we are applying new network planning criteria, which consider the customer value of the investment from a reliability perspective and applies a safety net based on the potential impact of a single event. We will continue to assess this approach as we move forward to best balance our customers' expectations around reliability and price.

At the distribution level, in addition to addressing localised demand, we are forecasting augmentation investment to specifically deal with voltage-driven constraints and conductor clearance issues.

We have allocated expenditure to address the performance of up to 45 feeder lines that are consistently underperforming.

To best target efforts towards our customers who are consistently experiencing supply interruption duration well beyond the MSS, we will review reliability outcomes annually, along with the solutions that are most cost effective.

We also plan to continue installing power quality monitors across the network so that we can proactively address momentary outages and voltage issues. Around two thirds of our distribution feeder lines are now monitored for power quality. Our proposal is to invest in a further 1,120 power quality monitors and an additional 100 power quality analysers.

Our asset renewal approach is aimed at reducing the risk of faults (both from a reliability and safety perspective) for the lowest whole-of-life cost. To do this efficiently we are continuing our investment in our condition monitoring capability to give us a better understanding of the state of the network. We are planning a significant replacement or refurbishment investment across our substation and powerline assets as well as for a range of other obsolescent technologies (including our radio communication network).

More information on our plans to ensuring reliability and quality of supply can be found at:

- *07.00.01 – (Revised) Asset Renewal Expenditure Forecast Summary*
- *07.00.02 – (Revised) CIA Expenditure Forecast Summary*
- *07.00.03 – (Revised) Customer Connection Initiated Capital Works Expenditure Summary*
- *07.00.04 – (Revised) Other System and Enabling Technologies Expenditure Forecast Summary*
- *07.00.05 – (Revised) Reliability and Quality of Supply Expenditure Forecast Summary.*

### **Peace of Mind – being there after the storm**

In preparation for each storm season, we will continue to routinely review our summer preparedness and improve our emergency management response capability. Our summer storm safety communications program will also continue and we will ensure our contact centre has the capacity to handle the call load following a major event when our customers need us the most.

Our expenditure in non-network assets across our vast service area, including our investment program in property, fleet, equipment and tools, remains critical to our people in delivering on our



emergency response. They also have access to a significant mobile generation and substation capability.

Our focus on enhancing the resilience of the network to the impact of storms is continuing through our asset refurbishment and replacement programs, and through targeted initiatives. For example, we are installing ‘spreaders’ (insulated rods) as a cost effective solution to prevent lines clashing during high winds and retrofitting fuses to protect against electrical overload.

More information on our plans to ensuring our resource capability for emergency response can be found at:

- *07.00.01 – (Revised) Asset Renewal Expenditure Forecast Summary*
- *07.00.06 – (Revised) Fleet Expenditure Forecast Summary*
- *07.00.08 – Property Expenditure Forecast Summary.*

## **Choice and Control**

In order to respond to the needs of our customers, and a changing industry and marketplace, we are progressively developing a ‘smarter’ grid and creating an open access platform that enables distributed energy resources and other applications to easily connect with our network to enhance customer choice.

We plan to be proactive, with investment in improving our real time data on network status, which will support better operational management decisions. This approach is necessary to support the change in the way customers are using the network. It will also allow us to achieve greater network utilisation (and potentially defer or avoid costly network investment), as well as general operational efficiencies. This capability, coupled with other voltage management initiatives, is particularly important in ensuring we can manage the network voltage issues associated with a higher penetration of solar energy systems.

To take advantage of this smart technology, we are targeting investment in new operational technology capabilities. This includes further investment in our distribution and outage management system, our SCADA control system and demand management system, as well as in telecommunications infrastructure.

More information on our plans to future proofing our network and business to give customers more choice and control can be found at:

- *07.00.04 – (Revised) Other System and Enabling Technologies Expenditure Forecast Summary*
- *07.00.07 – (Revised) ICT Expenditure Forecast Summary.*

## **Best Possible Price**

To support further efficiencies, over the next five-year period, we are implementing new technology-based capabilities, including better information and decision-making tools.

We are currently investing in management systems to enable efficiencies – this covers organisational performance information systems, as well as the systems that manage finance, human resources, safety and procurement. An investment is also continuing to be made in our spatial data and Geographic Information System to enable continued support, while delivering functional improvements.

Technology, and a focus on demand management, has allowed us to move our investment planning approach from being largely based on building more or bigger ‘poles and wires’ solutions, to a focus on finding the best, most cost-effective solution. Our delivery of 135MVA demand reductions to date over the regulatory control period 2010-15 is a clear demonstration of the capability developed in this area. This is equivalent to removing the demand of 36,000 houses or the demand of a regional city the size of Bundaberg.

We plan to strengthen this capability by progressively expanding the automation within the network. This will enable us to adopt emerging ‘smart’ technologies in the future that will optimise our ability to efficiently deliver the power supply needs of regional Queensland.

More information on our plans to implement new technology-based capabilities can be found at:

- *07.00.04 – (Revised) Other System and Enabling Technologies Expenditure Forecast Summary*
- *07.00.07 – (Revised) ICT Expenditure Forecast Summary.*

## **5 Forecasting method**

It is important to outline the methods that we have used to develop our capital expenditure forecasts in order to demonstrate how we meet the capital expenditure objectives set out in the NER. On 29 November 2013, we submitted our Expenditure Forecast Methodology<sup>122</sup> to the AER that detailed how we go about forecasting each of our capital expenditure categories.

This section expands on that methodology. It also briefly explains the AER’s approach to determining our expenditure requirement in the regulatory control period 2010-15, and concerns raised by the AER on our previous forecasting approach and how we have addressed them.

### **5.1 Previous period forecasting**

#### **AER approach**

In the regulatory control period 2010-15, the AER determined our:

- Asset Renewal capital expenditure based on historical levels
- CIA capital expenditure by adjusting our proposed forecast by applying a lower maximum demand and removing certain projects it considered were not justified
- Customer Connection Initiated Capital Works based on our average historical connection numbers and expenditure levels, escalated by the forecast customer growth rate
- Reliability and Quality of Supply capital expenditure based on historical levels, with an additional allowance for some specific programs
- Non-system capital expenditure by accepting our plant, vehicles, tools and equipment forecasts, removing an IT “change program” and two major property projects, although the Australian Competition Tribunal (the Tribunal) subsequently allowed these property projects to be re-included.

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<sup>122</sup> Refer to <https://www.ergon.com.au/network/network-management/future-investment/future-direction>.



## 5.2 Our capital expenditure forecasting approach in 2015-20

The process begins with the development of 'category level' expenditure forecasts. The methods that are used for each capital expenditure category are summarised in Section 5.5 below.

Each of the category level forecasts are then consolidated into a total capital expenditure amount and forecast (in nominal \$) for the final year of the previous period (i.e. 2014-15) and the five years of the regulatory control period 2015-20. Overheads are applied and allocated at this time.

Consistent with the requirements of the NER, the total capital expenditure forecasts are converted into 2014-15 real dollars by applying assumptions about CPI and other cost escalators.

The third step converts the aggregate capital expenditure forecasts (along with other key regulatory inputs) into revenue and pricing outcomes. Both the capital expenditure forecasts and the revenue and pricing outcomes are assessed against a number of factors, including:

- customer expectations regarding pricing and service outcomes, both within the regulatory control period 2015-20 and in future periods
- corporate and stakeholder expectations and commitments in respect of price and service delivery
- compliance with the NER and state imposed regulatory obligations
- current workforce delivery and capacity to deliver works in the regulatory control period 2015-20.

Where the aggregate capital expenditure forecasts or the revenue/pricing outcomes are inconsistent with the customer, corporate, workforce capability or regulatory expectations, refinements are made to the forecast volumes and the costs at the category level.

Prior to final internal approval, we assess the category level forecasts using, among other things:

- benchmarking and category based assessment techniques (such as augex and repex modelling) recommended and used by the AER as part of its own assessment processes
- independent verification of the expenditure forecasting methodology, assumptions and inputs
- historical and trend analysis
- detailed project reviews
- technical assessments
- governance and documentation reviews.

These techniques allow us to internally scrutinise category level forecasts, ensuring that the forecasts are prudent and efficient. Based on the outcomes of these assessments, category level forecasts are revised or substantiated with further evidence before the capital expenditure forecast is finalised.

## 5.3 Key assumptions

Clauses S6.1.1(4) and S6.1.1(5) of the NER require us to detail the key assumptions that underlie our capital expenditure forecasts and for the directors of Ergon Energy to certify the reasonableness of these assumptions. We consider key assumptions to be substitutes for facts or inputs necessary to prepare forecasts, where those facts or inputs are not known with certainty or cannot reasonably be derived from other data. We have therefore developed a key assumption

where it does not otherwise have an objectively verifiable factual basis on which to prepare our capital expenditure forecasts.

Table 52 outlines the key assumptions underpinning our capital expenditure forecasts for the regulatory control period 2015-20, consistent with NER requirements.<sup>123</sup> There have been no material changes since our October Regulatory Proposal. In June 2015, the directors of Ergon Energy reviewed the key assumptions and confirmed their continued application for this revised Regulatory Proposal.

**Table 52: Capital expenditure assumptions, 2015-20**

Assumption	Application
Our current company structure, ownership arrangements and service classification will continue.	The capital expenditure forecasts are based on continuing the current company structure. Any future restructuring could change Ergon Energy's cost structure and would require changes to our CAM.
We will deliver our forecast capital expenditure for 2014-15.	Based on the best estimates contained in the Submission RIN and excluding the impacts of exogenous events that impact works delivery (e.g. severe cyclones and flooding), we have sufficient internal and external resources and capability to deliver the forecast capital expenditure for 2014-15 and we do not expect that there will be any material works delivery issues in undertaking our capital projects and programs in accordance with our forecast capital expenditure for 2014-15.
Our current legislative and regulatory obligations will not change materially.	The capital expenditure forecasts are designed to comply with the current legislative and regulatory obligations. If any material changes occur, they may be treated as a cost pass through event.
We apply an "economic" customer value based approach to reliability, supported by "safety net" measures – this is in response to a Queensland Government Direction.	The capital expenditure forecasts – in particular, for CIA – have been prepared using these security criteria. We no longer apply deterministic security criteria.
Our MSS in our Distribution Authority will remain at 2010-11 levels until 2019-20.	The capital expenditure forecasts – in particular, for Asset Renewal and Reliability – have been designed to comply with the current MSS requirements set out in our 2014 Distribution Authority. Our current Distribution Authority has set our new MSS levels at the 2010-11 levels that had been previously set by the QCA under the <i>Electricity Act (1994)</i> and the Electricity Industry Code.
Actual maximum demand and customer connection growth will not vary materially from our forecasts.	The capital expenditure forecasts – in particular, for CIA and Customer Connection Initiated Capital Works – have been prepared to meet our demand forecasts, and have been informed by a range of factors, including our own market intelligence and customer feedback, and by relying on the best available external forecasts of endogenous variables within our forecast models, and the advice of independent experts on various inputs into these models.

<sup>123</sup> For the original directors' certification, refer to supporting document 06.01.06 – *Certification of reasonableness – expenditure forecast assumptions*.

Assumption	Application
We will apply a new Connections Policy – this will replace our Capital Contributions Policy, dated April 2005.	In accordance with the requirements of the NER, our cash contributions and gifted assets in our Customer Connection Initiated Capital Works capital expenditure forecasts reflect our contestability arrangements and are based on this new Connections Policy.
Our contestability arrangements that allow capital works to be undertaken by third parties will continue on the current basis.	The proportions of gifted assets and works undertaken by Ergon Energy in our Customer Connection Initiated Capital Works capital expenditure forecasts reflect our contestability arrangements.
Our forecast capital expenditure is based on our efficient costs for specific investments and programs of work, which are explained in this Regulatory Proposal.	Estimates for specified investments progressively undergo review, refinement, and revision as they progress through our Gated Governance Framework. By contrast, estimated unit costs are developed for 'programs of work' where there is uncertainty about their scope or location, or where there are significant volumes of recurrent activity.
Our parametric insurance will cover the financial impact of extreme wind-generated weather events and our works delivery and expenditure requirements will not be materially disrupted by extreme weather events.	Our capital expenditure forecasts have been prepared on the basis that the proposed inclusion of parametric insurance costs is allowed by the AER. Extreme weather events, such as cyclones or major flood events, can interfere with our ability to implement planned capital expenditure programs such as Asset Renewal.
Our labour, material and other cost escalations are realistic and reasonable.	We have based rate of change factors on existing enterprise agreement precedents (if applicable) and the independent expert advice on labour, material and other costs escalations (refer Jacobs (SKM) report). <sup>124</sup> This approach ensures that these escalators appropriately reflect the increases in the cost of materials and other non-labour inputs, as well as the skills required and the market factors driving the demand and supply of labour for the provision of our services.

## 5.4 We listened and responded to AER criticisms and concerns in 2010

The AER raised a number of issues in its May 2010 Distribution Determination about our capital expenditure forecasts for the regulatory control period 2010-15. We have implemented a range of measures to address these concerns, as shown in Table 53.

**Table 53: Addressing AER concerns in relation to our 2010-15 capital expenditure forecasts**

Category	AER concern	How Ergon Energy has responded
Asset Renewal	Asset ages overstate capital expenditure requirements	Enhanced defect classification and maintenance acceptability criteria
	Models use outdated data and have internal inconsistencies	Improved condition monitoring processes and systems
	Volumes do not use suitable data	Forecast volumes based on risk, ongoing maintenance cost, replacement cost, age and asset condition

<sup>124</sup> 06.02.02 – Jacobs: Cost Escalation Factors 2015-20 and 06.02.07 – Jacobs: Addendum Cost Escalation Factors 2015-20.

Category	AER concern	How Ergon Energy has responded
CIA	Maximum demand forecast too high	Developed new forecasting methodology incorporating top down and bottom up approaches
	Do not demonstrate efficiency of preferred options	Implemented gated governance framework supported by project business cases
	Cannot reconcile capital expenditure forecasts to plans	Developed clear augmentation plans at sub-transmission and distribution levels
Customer Connection Initiated Capital Works	Do not use prudent forecasting approach	Adopted new forecasting approach based on established macroeconomic indicators
Reliability	Do not demonstrate prudence / efficiency of expenditure, including volumes, benefits and timing	Presented clear justification supported by strategies and business cases
	Overlap with other funding allowances	Presented clear explanation of interdependencies with other allowances

## 5.5 Expenditure forecasting methodologies by category

This section summarises the expenditure forecasting methodologies that we have used for each category of capital expenditure. This expands on the information that we provided in our Expenditure Forecast Methodology. Further detail is contained in the Forecast Expenditure Summaries that we have prepared for each capital expenditure category.

We use a combination of replace on fail and proactive asset replacement approaches to forecast our **Asset Renewal capital expenditure**. We forecast our costs using standard estimates of replacement for each asset type. We forecast volumes using a combination of:

- discrete engineering analysis of individual projects in order to address specific known needs
- Condition Based Risk Modelling that uses available asset information and complex ageing models to predict asset failure probabilities and associated risks
- simplified predictive models that use statistical relationships between known asset information and future replacement needs, including the AER's repex model and historical trend models.

We forecast **CIA capital expenditure** using a combination of:

- detailed engineering analysis that compares forecast demand and capacity in the sub-transmission and distribution systems in order to identify emerging constraints. We then undertake detailed assessments of the least cost options to address the identified constraints
- the AER's augex model, which is a simplified predictive model that uses information on capacity, utilisation and demand patterns in network segments, and unit costs.

We forecast **Customer Connection Initiated Capital Works** using average historical costs and an econometric model that forecasts volumes using the following State macroeconomic variables: final demand; private investment – dwelling; and private investment – non-dwelling. These variables historically demonstrated the greatest causality and correlation to customer connection

outcomes. This aligns with the approach that the AER applied to forecast this capital expenditure for the regulatory control period 2010-15.

We forecast **Reliability capital expenditure** using average historical costs for comparable projects and an assumption that we will deliver three reliability projects each year. We forecast **Quality Improvement capital expenditure** on the basis that in the regulatory control period 2015-20 we will complete the installation of power quality monitors across our three phase and Single Wire Earth Return (SWER) distribution feeders and power quality analysers at our zone substations. These forecasts are also based on historical costs.

We forecast **Other System capital expenditure** on a project-by-project basis using a combination of vendor pricing, historical costs and standard labour rates and material costs.

**Fleet capital expenditure** is forecast using a model that forecasts the replacement date of vehicles and assets which are part of the Ergon Energy fleet. This model applies a set of replacement parameters to individual vehicle categories. The parameters applied take into account age and usage. The results from the model are a vehicle-by-vehicle lifecycle, from procurement through to replacement.

There are two elements to the **Property capital expenditure forecast**; these are the major and the minor programs. The major program is compiled based on using the Hub and Spoke strategy; with each item of expenditure (largely on property 'hubs') then going through the capital governance process to ensure the best value for money solution is achieved. The minor program (focused on 'spokes') uses optimisation to select the most efficient portfolio of works from all the candidate projects. In the case of the minor program, the candidate projects are largely determined as a result of regular inspections of existing properties.

There are other miscellaneous **Non-system capital expenditure** items relating to tools and equipment, mobile generation and IT equipment that are forecast separately.

## 5.6 Capital expenditure unit costs

Our supporting documents *07.00.09 – (Revised) Unit Cost Methodologies Summary for Ergon Energy* and *07.09.01 – (Revised) Network Capex Summary Model* note that we apply different approaches to developing our capital expenditure forecast for "specified investments" and our "program of works".

We also use standard unit costs in the development of our ICT (e.g. infrastructure renewal)<sup>125</sup> and fleet<sup>126</sup> capital expenditure forecasts. Details of how program and project estimates are developed for our property investments are outlined in our supporting document *07.00.08 – Property Expenditure Forecast Summary*.

### Specified investments

Ergon Energy develops a cost estimate for all specified investments when there is certainty around the constraint, scope, location and timing of the investment. Our estimating system is designed such that as each specified investment progresses through Ergon Energy's Gated Governance

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<sup>125</sup> *07.07.03 – ICT Forecasting Method and Approach.*

<sup>126</sup> *07.00.06 – (Revised) Ergon Energy Fleet Expenditure Forecast Summary.*

framework (obtaining financial approval for investments) the estimate progressively undergoes review and refinement and is updated accordingly.

These investments begin with one or more standard estimates. Standard estimates are ready-made estimates based on standard designs and drawings. Estimating specialists create the standard estimates and update these when standard designs change. Effectively these estimates are templates that are modified to accommodate the specific requirements of the investment required.

The repository for these estimates is located in internal IT systems. Standard estimates:

- are sufficiently accurate for forecasting several years ahead
- provide a consistent and efficient basis for producing project cost estimates for works repeatedly undertaken
- includes appropriate structures for estimated direct and known costs and on-costs dependent on its intended use
- exclude the cost of borrowings, unknown costs, and uncertainty allowances.

There are a limited number of specified investments that have not utilised a standard estimate. These exceptions occur when the proposed investment is unlikely to be repeatedly undertaken. An example would be a new specific project such as an IT software purchase.

As a specified project progresses, it moves through five different phases and the estimating system supports the management of this progression. The five phases are Pre-Concept, Concept, Development, Implementation and Finalisation.

## Program of works

Where there is some uncertainty in the investment scope, location or if the investment involves significant volumes of recurrent work, we develop our expenditure forecast based on a prediction of volumes multiplied by a unit cost.

The approach adopted to develop each program estimate depends on the availability, comparability and granularity of historical data. Broadly, we apply one of the following three approaches:

- *Historical average cost program estimates* – we develop some program estimates based on an average of recorded historical costs. This is the case when future activities and costs are expected to reflect the historical activities and associated costs. These costs include all direct costs related to the investment such as labour, materials, equipment, mobilisation and contractors' costs. The averaging of these historical costs over multiple years provides a robust estimate of future costs and the program estimate applied to our capital expenditure forecast.
- *Bottom up program (product) estimates* – where historical data is not available or where data is not reflective of future activities or costs, we develop bottom-up program estimates using a scope of work that reflects future activity. Specialist estimators then use the scopes to estimate a unit cost. Depending on the nature of the program and the information available, we assess unit costs against at least one of the following to validate the robustness of each estimate: one-off historic costs; market costs; market estimates; and peer review by our subject matter experts. Estimates are updated for variations in labour rates and material costs.



- *Application of uplift factors* – unlike historical average cost estimates, bottom up program estimates are direct lean costs required to perform the intended activity. We apply appropriate mobilisation and cost uplift factors specific to the program activities.

## 6 Outcomes for customers

As a result of our investments, we are committing to the customer benefits shown in Table 54.

**Table 54: Customer benefits and related risks**

Customer benefit	Related risks
<b>Our approach to safety</b>	
<ul style="list-style-type: none"> <li>• Our goal is for our safety performance to stand with the best in our industry... to be Always Safe.</li> <li>• Our expenditure on renewal, maintenance and network operations are all focused on managing safety risks.</li> </ul>	<ul style="list-style-type: none"> <li>• Unforeseen safety related issues or damage caused by weather events may arise during the period that may result in the reprioritising of expenditure towards addressing them or lead to passing on cost increases in the period following.</li> </ul>
<b>A reliable, quality electricity supply</b>	
<ul style="list-style-type: none"> <li>• We'll maintain recent overall improvements to power supply reliability... and continue to improve the experience of customers who are suffering outages well outside our standards.</li> </ul>	<ul style="list-style-type: none"> <li>• Further reductions to the expenditure proposals, seasonal weather conditions or delivery delays (due to significant weather related events/reprioritisation of expenditure) may impact the reliability performance in some areas.</li> <li>• Improvements in the areas of the network currently requiring attention will need to be prioritised based on the level of available funds.</li> <li>• We will be monitoring the impact of the changes to the way we are managing security of supply to ensure they do not impact to reliability in longer-term.</li> </ul>
<b>Our disaster response</b>	
<ul style="list-style-type: none"> <li>• We'll be there after the storm, prepared and with the resources to respond to whatever Mother Nature delivers.</li> </ul>	<ul style="list-style-type: none"> <li>• If approved, the operational resourcing levels outlined in our Regulatory Proposal will maintain our current emergency response capability.</li> </ul>
<b>Meeting service expectations</b>	
<ul style="list-style-type: none"> <li>• We'll meet our guaranteed services commitments. If we don't, we'll pay you.</li> </ul>	<ul style="list-style-type: none"> <li>• As expectations around choice and control evolve, our service standards, especially in the connections and communications area may need to be reviewed.</li> </ul>
<b>A future of customer choice</b>	
<ul style="list-style-type: none"> <li>• We're looking to the future – and evolving the network to best support customer choice in economic electricity supply solutions.</li> </ul>	<ul style="list-style-type: none"> <li>• We have made assumptions on the rate of industry change in our planning, and the market reforms needed to support it. If the market reforms are ineffective, and/or the rate that customers take up new technologies or the type of technology that emerges is significantly different, our ability to respond could be limited.</li> </ul>
<b>The best possible price</b>	
<ul style="list-style-type: none"> <li>• After reducing charges for the use of our network in 2015-16, we're targeting to keep charges overall at 2014-15 levels for the remaining four years out to 2020.</li> <li>• By separating metering service charges from our network charges, we</li> </ul>	<ul style="list-style-type: none"> <li>• Network charges are only one part of a customer's bill. Other costs will also influence what a customer pays. Adjustments to incentive schemes, or rate of return adjustments could increase or decrease revenues requirements.</li> <li>• For customers on regulated retail prices (Notified Prices) the actual price impact of our Regulatory Proposal will depend on the</li> </ul>

Customer benefit	Related risks
are supporting customer choice in providers.	<p>approach the QCA takes in setting prices in the future.</p> <ul style="list-style-type: none"> <li>The financial target we have set is a challenge. We will require significant reductions in costs in the future. There is a risk that further reductions would not be sustainable, and may affect service delivery and the safety of the network.</li> </ul>

## 7 Meeting Rule requirements

The NER places obligations on Ergon Energy to provide information to assist the AER make a decision on the total capital expenditure for the period. We believe there is sufficient evidence in this proposal and supporting documents to satisfy the AER that our proposed capital expenditure reflects the capital expenditure criteria.

In addition to the information contained in each capital expenditure category summary document, our supporting document *06.01.05 – (Revised) Meeting Rule Requirements for Expenditure Forecasts* provides substantial detail on:

- why the forecasts enable Ergon Energy to achieve each of the capital expenditure objectives
- why Ergon Energy believes there is sufficient evidence to satisfy the AER that the forecasts meet the capital expenditure criteria.

The approach outlined in *06.01.05 – (Revised) Meeting Rule Requirements for Expenditure Forecasts* remains applicable to this revised Regulatory Proposal. Where applicable or necessary, Ergon Energy has supplied updated information regarding any material changes to our forecasts and the application of the relevant NER requirements in the attachments that support this revised Regulatory Proposal.

## 8 Supporting documentation

The following documents referenced in this appendix accompany our Regulatory Proposal:

Name	Ref	File name
Ergon Energy Expenditure Benchmarking	0A.02.01	Ergon Benchmarking
(Revised) Legislative and Regulatory Obligations and Policy Requirements	01.01.01	(Revised) Legislative and Regulatory obligations
(Revised) Meeting Rule Requirements for Expenditure Forecasts	06.01.05	(Revised) Meeting the Rules requirements
Certification of reasonableness – expenditure forecast assumptions	06.01.06	Certification of reasonableness – expenditure forecast assumptions
Jacobs: Cost Escalation Factors 2015-20	06.02.02	Cost Escalation Factors 2015-20 SKM
Jacobs: Addendum Cost Escalation Factors 2015-20	06.02.07	Jacobs Addendum Cost Escalation Factors 2015-20
(Revised) Asset Renewal Expenditure Forecast Summary	07.00.01	(Revised) Asset Renewal Expenditure Forecast Summary
(Revised) CIA Expenditure Forecast Summary	07.00.02	(Revised) Corporation Initiated Augmentation Expenditure Forecast Summary



Name	Ref	File name
(Revised) Customer Connection Initiated Capital Works Expenditure Forecast Summary	07.00.03	(Revised) Customer Initiated Capital Works Expenditure Forecast Summary
(Revised) Other System and Enabling Technologies Expenditure Forecast Summary	07.00.04	(Revised) Other System Enabling Technologies Expenditure Forecast Summary
(Revised) Network Reliability and Quality of Supply Expenditure Forecast Summary	07.00.05	(Revised) Reliability and Quality of Supply Forecast expenditure Forecast Summary
(Revised) Fleet Expenditure Forecast Summary	07.00.06	(Revised) Fleet expenditure forecast summary
(Revised) ICT Expenditure Forecast Summary	07.00.07	(Revised) ICT expenditure forecast summary
Property Expenditure Forecast Summary	07.00.08	Property expenditure forecast summary
(Revised) Unit Cost Methodologies for Ergon Energy Summary	07.00.09	(Revised) Unit Cost Methodologies summary
ICT Forecasting Method and Approach	07.07.03	Expend Forecast Method 2015-2020 Indiv Business Unit ICT
(Revised) Network Capex Summary Model	07.09.01	(Revised) Network Capex Summary Model
Our Capital Governance and our plans, policies and procedures	07.09.17	Governance, Plans, Policies and Procedures
Regulatory Information Notice	N/A	Our response to the AER's RIN is contained in a number of files attached to this proposal. Information provided in our RIN is correct as at the time of our October Regulatory Proposal, unless otherwise stated

# Appendix C: Rate of Return

## Introduction and summary of changes

The capital already invested in the network and the financing and costs associated with that capital, has by far the greatest impact on prices. The cost of funding this capital is determined by multiplying the value of the asset base by the proposed rate of return.

It is more important than ever for Ergon Energy to ensure we have an appropriate rate of return to attract funds should we be required to.

Using advice of experts and consistent with the views of private sector industry participants, our required equity returns are consistent with statutory objectives, but higher than what was calculated by the AER in its Rate of Return Guideline. A departure from the guideline is therefore necessary. Our required cost of debt is relatively consistent with the AER's guideline calculations.

Ergon Energy has maintained our approach to calculating the rate of return. However, we have updated our proposal to reflect the latest market information.

## Customer benefits

We have been able to propose a much lower rate of return, thanks to current market conditions, which is again supporting our commitments around electricity prices.

The updated rate of return of 7.41% in our revised Regulatory Proposal is below the 8.02% we proposed as a placeholder in October 2014 and a reduction on the previous period's 9.72% and the 8.50% rate set in the 2005-10 period (under the regulation of the QCA).

This supports our target to keep overall increases in network charges at 2014-15 levels for the four remaining years of the regulatory control period 2015-20.

## Appendix C: Rate of Return

### 1 Introduction

This appendix describes Ergon Energy's approach to determining the rate of return that we propose to apply to Standard Control Services in the regulatory control period 2015-20.

We have updated our required rate of return from 8.02% in our October Regulatory Proposal to 7.41% (nominal), primarily based on changes to market conditions at the time our proposal was finalised. The reduction in the required rate of return largely reflects changes in market parameters. We have revised our proposed approach to estimating the cost of debt so that it better reflects NER requirements.

A reduced rate of return improves what we previously proposed as our 'best possible price' commitment outlined in *0A.00.01 – An Overview, Our Regulatory Proposal 2015-20*. We noted at the time of our October Regulatory Proposal that, to the extent that financing costs continue to improve relative to the assumptions contained in our proposal, we expected the AER to establish a rate of return commensurate with these conditions to deliver even better outcomes for customers in terms of what we charge to build, operate and maintain our network.

The AER did not do this. Instead the AER's Preliminary Determination imposed substantially lower allowances than any market-based measure of the costs of a benchmark network business implementing efficient financing practices.

As detailed in this appendix and supporting evidence, in relation to each of the AER's preliminary decisions on the rate of return, the AER fails to accommodate the contemporaneous market reflective return that the benchmark firm would actually earn in efficient capital markets.

Specifically:

- With respect to the expected return on equity, the AER's approach of combining a very long run market risk premium which significantly understates the degree of risk we face with an extremely short run base interest rate delivers an allowed rate of return on equity clearly below the prevailing hurdle rates for our industry. The Reserve Bank of Australia (RBA) has now explained that the required return on equity has been relatively stable over recent months as the equity risk premium has increased to offset the material decline in base interest rates. The AER's Preliminary Determination fails to give any real weight to three of the four models that it has acknowledged are relevant. The AER must reflect these facts in its decisions.
- With respect to gamma, the AER's approach eschews estimates for gamma drawn from contemporaneous equity markets in favour of a 'conceptual analysis'. This imposes an artificial valuation that is substantially higher than any benchmark efficient firm would experience when seeking to raise capital in the real marketplace and does not represent the "value of imputation credits" within the meaning of the NER.
- With respect to the expected return on debt, the AER acknowledges that the benchmark efficient firm would have a portfolio of long-term debt with a staggered portfolio of issuance and maturity. However, the AER's approach depresses the allowed return below the level of costs associated with such a staggered portfolio in order to claw-back allegedly inflated gains from the immediately prior regulatory control period. These gains, to the extent they exist, can only have resulted from non-systematically selecting debt allowances for the whole five year regulatory control period over extremely short averaging windows in volatile debt markets.

All of these features of the AER's preliminary decision are contrary to the NER requirements in that they result in a significant divergence between the regulated allowances and efficient financing costs in prevailing market conditions.

In a number of respects, the AER's Preliminary Determination has applied confused and incorrect decision making tests. In most instances these tests appear to be a legacy of former regulatory arrangements that the Australian Energy Market Commission (AEMC) deliberately repealed.

In the past:

- The AER was required to use the Sharpe-Lintner Capital Asset Pricing Model (SL CAPM) when regulating electricity networks and strongly encouraged to use it for the gas networks. However, now *due regard must* be had to all the relevant models. We are concerned that the AER's approach is to start from the proposition that the SL CAPM is the incumbent model and, no matter how strong the case, it cannot be departed from.
- For electricity, the previous rules required the AER to apply its Statement of Regulatory Intent unless there was "persuasive evidence" to depart from it. However, now the requirement is to make the decision that best promotes the allowed rate of return objective whether or not that position was set out in the Rate of Return Guideline. Despite this, in a number of respects the AER's Preliminary Determination seeks to impose a substantial (and in some cases impractically high) hurdle upon the business' claims rather than setting the allowance on the best available information.

These previous approaches have now been superseded. When construed in the context of the regulatory instruments, the task at hand and the case law,<sup>127</sup> the decision-making test is required to take into account all of the relevant models and other inputs (which quite clearly must include fully estimating each model) and give *due weight* to each of these inputs in reaching a decision that best promotes the rate of return objective.

Our October Regulatory Proposal was established on the basis of the decision-making test outlined above. Our revised Regulatory Proposal, as explained below, has also been established on the same basis.

## 1.1 Context of our revised proposal

In the current regulatory process, there are four distinct avenues by which Ergon Energy may express our views:

- (a) in the regulatory proposal itself (lodgement of which is provided for in clause 6.8.2 of the NER)
- (b) in information "accompanying" the regulatory proposal (which a number of rules recognise as a distinct category of material from the regulatory proposal itself – see clauses 6.9.1(a)(3) and 6.11.1(b)(1) of the NER)
- (c) in a submission lodged by the business during the periods in which the AER invited submissions on the Preliminary Determination (see clause 6.9.3(a)(5) of the NER)
- (d) in the submissions in response to the revocation and substitution of the Preliminary Determination (see clause 11.60.4(b) of the NER which expressly states that "any person" may make a submission and which adds that "Without otherwise limiting the manner in which

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<sup>127</sup> Re Dr Ken Michael AM; Ex parte EPIC Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231.

the affected DNSP may make such submissions, the affected DNSP may make a submission in the form of revisions to the *regulatory proposal* that it submitted to the AER in relation to the distribution determination referred to in paragraph (a).”).

This appendix relates to the last of these avenues. Therefore, this revised Regulatory Proposal forms part of our submission under (d) above and must be considered with other relevant material now the revocation and substitution process has commenced. In addition to our October Regulatory Proposal, this includes:

- all relevant evidence and material provided by Ergon Energy to the AER since our October Regulatory Proposal, including submissions made as part of the reset processes for the NSW and ACT DNSPs
- our submission in response to the AER’s Preliminary Determination
- supporting evidence, documentation and material submitted with our submission to the AER’s Preliminary Determination, in particular:
  - our submission in response to the rate of return (equity)
  - our submission in response to the rate of return (cost of debt)
  - our submission in response to gamma
  - expert reports, models and other evidence accompanying these submissions.

## 1.2 Commercial and market context

The remaining value of capital investments Ergon Energy has made is represented by the approved RAB. Prices are set to enable us to recover our investment over time (a return of that capital or depreciation, referred to in Chapter 3), as well as the cost of funding investments through debt or equity (a return on capital or allowed rate of return).

An allowance for the return on capital is therefore a key revenue building block making up our revenue allowance. The return on capital is calculated as the product of the allowed rate of return and the opening value of the RAB used to provide Standard Control Services for that regulatory year.<sup>128</sup>

As an asset intensive business, Ergon Energy’s financing requirements are substantial. Table 55 sets out the assumed funding requirements for Ergon Energy at the beginning of the regulatory control period.

**Table 55: Assumed funding requirements, \$m**<sup>129</sup>

Assumed financing requirement represented by Opening RAB	\$10,055.83
Investment requiring debt financing	\$6,033.50
Investment requiring equity financing	\$4,022.33

<sup>128</sup> NER, clause 6.5.2(a).

<sup>129</sup> Assumes capital structure consistent with the AER’s Rate of Return Guideline.

Because all distribution network businesses are highly capital intensive, the return on capital tends to be the most significant of the building blocks that make up the ARR. This has been recognised by the AEMC in the context of the 2012 Rule change process:<sup>130</sup>

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“Given the capital intensity of energy networks, the rate of return is one of the key determinants of the network prices that consumers pay. The nature of the energy network sector requires service providers to make significant investments in assets over time to maintain and improve their networks. The rate of return allows service providers to attract the necessary funds from capital markets for these investments and service the debt they incur in borrowing the funds.”

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In the regulatory control period 2010-15, the return on capital made up more than half of Ergon Energy’s total revenue requirement. The methods used to calculate the return on capital is therefore also one of the more contentious issues when establishing future revenue allowances. The determination of a forward-looking rate of return is an inherently subjective exercise as many of the parameters, in particular the expected return on equity, are not readily observable. Because of the subjectivity and sensitivity to future revenues, the rate of return has been the most debated issue in recent policy developments and regulatory reviews.

The allowed rate of return needs to be commensurate with the return that an investor would require to commit capital to the business, having regard to prevailing conditions in the market for funds.<sup>131</sup> The AEMC has acknowledged that:<sup>132</sup>

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“If the allowed rate of return is not determined with regard to the prevailing market conditions, it will either be above or below the return that is required by capital market investors at the time of the determination. The Commission was of the view that neither of these outcomes is efficient nor in the long term interest of energy consumers.”

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The AER has also noted the adverse consequences of a rate of return set too high or too low:<sup>133</sup>

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“A good estimate of the rate of return is necessary to promote efficient prices in the long term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and

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<sup>130</sup> AEMC (2012), *Final Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, pp.ii-iii.

<sup>131</sup> NER, clause 6.5.2(g). In the revised NER this clause now only relates to the return on equity. This still applies to the extent relevant in relation to the return on debt, recognising that under the trailing average approach the return on debt will reflect the cost of debt raised historically, with the prevailing return on debt ‘averaged in’ to that trailing average each year as part of the annual update.

<sup>132</sup> AEMC (2012), *Ibid*, p44.

<sup>133</sup> AER (2013a), *Better Regulation: Rate of Return Fact Sheet*, December 2013.

reliability may decline. On the flip side, if the rate of return is set too high, the network business may seek to spend too much and consumers will pay inefficiently high prices.”

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While risks occur if the rate of return is set too high or low, there is evidence to suggest that regulatory error tends to have asymmetric consequences. The Productivity Commission has stated:<sup>134</sup>

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“Over-compensation may sometimes result in inefficiencies in timing of new investment in essential infrastructure (with flow-ons to investment in related markets), and occasionally lead to inefficient investment to by-pass parts of the network. However, it will never preclude socially worthwhile investments from proceeding.

On the other hand, if the truncation of balancing upside profits is expected to be substantial, major investments of considerable benefit to the community could be forgone, again with flow-on effects for investment in related markets.

In the Commission’s view, the latter is likely to be a worse outcome.”

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In reporting to the Ministerial Council on Energy as part of its review of energy network pricing, the Expert Panel found:<sup>135</sup>

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“Even if there is no systemic bias in regulatory decisions, the costs of regulatory error are asymmetric, i.e., errors leading to suppression of rates of return and under-provision of infrastructure are likely to outweigh the costs of errors leading to extraction of above-normal rates of return from regulated infrastructure.”

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The consequences of under-investment in electricity network infrastructure in Queensland are well known. Following a period of extended outages arising from a severe storm season and hot weather, the Queensland Government commissioned a review of electricity distribution and service delivery (the ESDS review), which concluded:<sup>136</sup>

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“While the Panel accepts that it would not be economically prudent to “gold plate” the networks, it is clear that there needs to be sufficient expenditure to maintain them adequately and to develop them to meet new customer demands. For the reasons explained in this Report, the

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<sup>134</sup> Productivity Commission (2001), *Review of the National Access Regime, Report no. 17*, AusInfo, Canberra, p83.

<sup>135</sup> Expert Panel on Energy Access Pricing (2006), *Report to the Ministerial Council on Energy*, April 2006, p77.

<sup>136</sup> Independent Panel (2004), *Detailed Report of the Independent Panel, Electricity Distribution and Service Delivery for the 21<sup>st</sup> Century*, p8.



Panel believes that the networks have not had sufficient expenditure outlaid on them to adequately maintain them and to meet increased demand from growth...”

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The NER establish a framework based on the forward looking benchmark costs of raising debt and equity from the market to fund investment. The application of this same assumption to government and non-government owned businesses was explicitly considered and endorsed by the AEMC<sup>137</sup> and AER.<sup>138</sup>

It has therefore always been relevant to Ergon Energy to set an allowed rate of return at a level that would be sufficient to attract private capital, regardless of our government ownership. As acknowledged by the AEMC<sup>139</sup> and AER,<sup>140</sup> this is also consistent with the principle of competitive neutrality, which underpinned the corporatisation of government-owned businesses, including Ergon Energy.

### **Analysing the level of risk our business faces**

The AER should wholly re-work its analysis of risk. The AER’s Preliminary Determination analysis was based in significant part on a report it commissioned from Frontier Economics. Frontier Economics has now reviewed the use to which its work has been put by the AER. It relevantly states:

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“The fact that the precise relationship between leverage and equity beta is not known with certainty does not mean that that the effect of leverage on beta should be disregarded when making comparisons between estimated equity betas. Such an approach would be at odds with accepted finance and regulatory practice.

The “financial risks” that we considered in our 2013 report for the AER are not the same as financial leverage and do not substitute for the leverage component of equity beta. The AER appears to have misunderstood this point in our 2013 report.”<sup>141</sup>

The evidence that the AER presents in relation to US utility betas supports a re-levered equity beta estimate of close to 1.”

“There have been developments in the roll-out and adoption of disruptive technologies since our 2013 report. There is more uncertainty about the future of the industry now than there was even two years ago, and it is not unreasonable to think that investors would take this into account when allocating scarce capital to this industry.

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<sup>137</sup> AEMC (2012). Ibid.

<sup>138</sup> AER (2013b), *Better Regulation, Explanatory Statement, Rate of Return Guideline*, December 2013.

<sup>139</sup> AEMC (2012), Ibid, p79.

<sup>140</sup> AER (2013b), Ibid, p211.

<sup>141</sup> Frontier Economics (2015), *Review of the AER’s conceptual analysis for equity beta*, May 2015, para 10, p4.



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The AER suggests that any systematic component of disruptive technology risk would be captured in its equity beta estimates. Our view is that this is very unlikely.

The AER suggests that to the extent that the risks are non-systematic in nature, those risks would more appropriately be compensated through regulated cash flows (such as accelerated depreciation of assets). However, notwithstanding that the AER recognises that disruptive technologies may increase the risks faced by NSPs, the AER has made no allowances for these risks either through the rate of return or through regulated cash flows.”<sup>142</sup>

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As clearly evidenced by this additional work, the AER has failed to properly recognise the effect of a 60% leverage on the beta.

### 1.3 Legislative context

The AER’s approach to the return on capital is incorrect in relation to equity, debt and gamma. The NER requires the AER to make a decision that sets an allowed rate of return that is commensurate with prevailing market conditions.<sup>143</sup> While real world equity returns have remained virtually constant, the AER’s regulatory allowance has declined radically in lock-step with unprecedented falls in base interest rates.

The key reasons for the mismatch between the allowance and commensurate market returns are:

- The AER adopts the contemporaneous government bond rate as the estimate of the risk free rate in circumstances where the rate is at historically low levels without making adjustments to the rate of return to ensure the allowed rate of return objective is met.
- The AER combines a historically low short term risk free rate with a risk premium equal to the long run historical average of excess market returns.
- The AER fails to give any real weight to several of the key relevant finance models – contrary to the requirements of the NER to have regard to the insights arising from estimating all these models.
- The AER implements its favoured SL CAPM in an inconsistent and unpredictable way that causes the regulatory allowance to oscillate and vary up and down more profoundly than observed equity returns as we move through the economic cycle and which, even on a structural basis, delivers downwardly biased results for firms that are claimed to be ‘low risk’.

Each of the three aspects of the rate of return – equity,<sup>144</sup> debt,<sup>145</sup> and gamma<sup>146</sup> – need to be amended so that the allowances are commensurate with market-based returns and in order for the regulatory allowance to foster long-term efficient investments necessary for the supply of safe and reliable electricity in the long-term interest of consumers.

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<sup>142</sup> Frontier Economics (2015), *Review of the AER’s conceptual analysis for equity beta*, May 2015, para 10, p4.

<sup>143</sup> NER, clause 6.5.2(g).

<sup>144</sup> NER, clause 6.5.2(g).

<sup>145</sup> NER, clause 6.5.2(i).

<sup>146</sup> NER, clause 6.5.3.

Despite contrary assertions by the AER's economic consultants when discussing gamma,<sup>147</sup> these decisions on aspects of the rate of return are closely connected with each other because together they determine the return that investors in the business can earn on capital invested. All three components must comprise a consistent, prevailing market-based return that the benchmark firm would actually face (and can replicate) in the regulatory control period.

The regulatory framework in relation to the provision of Standard Control Services to our customers is contained in the NEL. The Revenue and Pricing Principles allow us to "at least" recover the efficient costs of providing these services.<sup>148</sup>

One of these Revenue and Pricing Principles stipulates that the price of these services "should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates." This allowed rate of return reflects the efficient costs of financing the capital investments Ergon Energy needs to make in order to deliver our services to our customers.

The NER now requires the allowed rate of return to achieve the following objective (the 'allowed rate of return objective'):<sup>149</sup>

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“...the rate of return for a *Distribution Network Service Provider* is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the *Distribution Network Service Provider* in respect of the provision of *standard control services*...”

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The substantive NER requirements mandate the decision to deliver efficient market based assessments for each of these three components using the best available information on the current effective financing costs for the benchmark efficient firm.

Importantly, consistent with the principles of incentive regulation, the NER requires that the allowed rate of return is based on the efficient benchmark costs of raising debt and equity from the capital markets to fund these investments. It is not based on Ergon Energy's actual financing costs. This provides an incentive for us to achieve efficiency gains and ensures that we cannot be rewarded for inefficient funding practices and costs.<sup>150</sup>

#### 1.4 The Rate of Return Guideline

The AER must publish, and has published, a Rate of Return Guideline which addresses each of the issues that determine the rate of return on capital. Specifically, the Rate of Return Guideline<sup>151</sup> must set out:

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<sup>147</sup> Handley J. (2015), *Advice on the NERA Report: Estimating Distribution and Redemption Rates for the Australian Energy Regulator*, 20 May 2015.

<sup>148</sup> NEL, clause 7A.

<sup>149</sup> NER, clause 6.5.2(c).

<sup>150</sup> AEMC (2012), p12.

<sup>151</sup> NER, clause 6.5.2(n).

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(1) the methodologies that the *AER* proposes to use in estimating the *allowed rate of return*, including how those methodologies are proposed to result in the determination of a return on equity and a return on debt in a way that is consistent with the *allowed rate of return objective*; and

(2) the estimation methods, financial models, market data and other evidence the *AER* proposes to take into account in estimating the return on equity, the return on debt and the value of imputation credits referred to in rule 6.5.3.”

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The Rate of Return Guideline is not binding and must be departed from if the outcomes of the guideline will not produce a rate of return that is consistent with the requirements of clause 6.5.2 of the *NER* and/or will not satisfy the allowed rate of return objective. This was not done in the *AER*'s preliminary decision.

### 1.5 *NER* requirements

The substantive requirements for the *AER*'s decision to deliver efficient market based assessments for each of these three components using the best available information on the current effective financing costs for the benchmark efficient firm are set out below:

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“(b) The allowed rate of return is to be determined such that it achieves the allowed rate of return objective.

(c) The allowed rate of return objective is that the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk ... ”

“(e) In determining the allowed rate of return, regard must be had to:

(1) relevant estimation methods, financial models, market data and other evidence;

(2) the desirability of using an approach that leads to the consistent application of any estimates of financial parameters that are relevant to the estimates of, and that are common to, the return on equity and the return on debt; and

(3) any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.

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(g) In estimating the return on equity under paragraph (f), regard must be had to the prevailing conditions in the market for equity funds.

...

(j) Subject to paragraph (h), the methodology adopted to estimate the return on debt may, without limitation, be designed to result in the return on debt reflecting:

(1) the return that would be required by debt investors in a benchmark efficient entity if it raised debt at the time or shortly before the making of the distribution determination for the regulatory control period;

(2) the average return that would have been required by debt investors in a benchmark efficient entity if it raised debt over an historical period prior to the commencement of a regulatory year in the regulatory control period; or

(3) some combination of the returns referred to in subparagraphs (1) and (2).

(k) In estimating the return on debt under paragraph (h), regard must be had to the following factors:

...

(4) any impacts (including in relation to the costs of servicing debt across regulatory control periods) on a benchmark efficient entity referred to in the allowed rate of return objective that could arise as a result of changing the methodology that is used to estimate the return on debt from one regulatory control period to the next.”<sup>152</sup>

“ $\gamma$  is the value of imputation credits.”<sup>153</sup>

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Many features of the AER’s decision are contrary to the requirements of the NER quoted above in that they result in a significant divergence between the regulated allowances and efficient financing costs in the prevailing market.

### **Inter-period look-backs or claw-backs are impermissible**

With respect to the allowed return on debt, the AER’s approach involves a departure from the prevailing financing costs of a benchmark efficient firm (given that it would have a portfolio with staggered debt issuance). The AER’s approach also explicitly seeks to impose an inter-period

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<sup>152</sup> NER, clause 6.5.2.

<sup>153</sup> NER, clause 6.5.3.

'look-back' when setting the allowance. Under-compensating Ergon Energy now, in order to reverse alleged past 'windfall gains' is contrary to the express language in the NER and is inconsistent with the fundamental basis for the economic regulatory system upon which the network regulatory aspects of the NEM are based.

The Australian economic regulatory system is an "incentive based" system known as "CPI-X" regulation. That system was based upon the "RPI-X" system initially developed by the UK's Royal Treasury for the regulation of British Telecom in the 1980s. The key aspect of this system is that, subject to well defined carry-over mechanisms, the business is allowed to earn an efficient contemporaneous benchmark return. The business can profit by out-performing the benchmark (or suffer losses where it under-performs the benchmark). Except to the limited extent of a well-defined incentive carry-over mechanism, at the time of each regulatory determination the question of whether the business out-performed or under-performed the benchmark is not a relevant consideration.

In this regard, we are particularly concerned that the AER's Preliminary Determination seeks to "claw back" alleged past wind-fall gains on past debt allowances by under-compensating the business relative to the AER's own current assessment of our efficient debt financing costs.

The AER did not provide any analysis or assessment of past over-compensation by Ergon Energy in its Preliminary Determination. The AER has assumed that such past over-compensation existed and that it was of a similar magnitude to the prospective under-compensation under the AER's proposed guideline transition. Our analysis of this issue demonstrates that there was no past windfall gain for Ergon Energy over the past three historical regulatory control periods from 2001 to 2015. In fact, there were windfall losses using a weighted trailing average approach which is the only weighting approach that can be used to undertake this analysis.<sup>154</sup>

## 2 Our proposed rate of return

Ergon Energy has developed our rate of return proposal with the objective of obtaining the best possible estimate under the NER, which reflects prevailing conditions in the market for funds.<sup>155</sup> Assuming 60% gearing<sup>156</sup>, the proposed estimate for the first year of the regulatory control period is provided in Table 56 below.

**Table 56: Summary of key rate of return parameters, 2015-20<sup>157</sup>**

Key parameter	Ergon Energy's calculation
Return on equity	10.00%
Return on debt	5.68%
Rate of return	7.41%

<sup>154</sup> See our supporting submission, *QTC – Return on debt transition analysis*.

<sup>155</sup> S6.1.3(9) of the NER provide that Ergon Energy's building block proposal must provide a calculation of the proposed return on equity, return on debt and allowed rate of return, for each regulatory year of the regulatory control period, in accordance with clause 6.5.2, including any departure from the methodologies set out in the Rate of Return Guideline and the reasons for that departure.

<sup>156</sup> Consistent with the AER's Rate of Return Guideline.

<sup>157</sup> To calculate the WACC, the return on equity value has been rounded to 10.5%, consistent with the PTRM.

This is an indicative ‘placeholder’ estimate reflecting prevailing market rates in the period prior to the submission of this Regulatory Proposal. Consistent with the AER’s normal practice, the return on debt and equity will be updated prior to the AER’s Substitute Determination.

The return on debt will then be updated annually during the regulatory control period in accordance with the trailing average approach,<sup>158</sup> based on averaging periods to be agreed with the AER. For the purpose of this Regulatory Proposal, our estimate of the return on debt for the first year of the regulatory control period has been applied to each of the remaining four years of the regulatory control period. Section 4.9 of this appendix sets out the method of calculation of the proposed rate of return on debt which Ergon Energy proposes to apply in the first and each subsequent year of the regulatory control period.

The basis of Ergon Energy’s proposal is summarised in Table 57, including identifying where Ergon Energy has departed from the AER’s Rate of Return Guideline.

**Table 57: Overview of Ergon Energy’s proposed approach to estimating the allowed rate of return**

Allowed rate of return component / parameter	Rate of Return Guideline approach/value	Ergon Energy’s proposal and identified departures
Rate of return on equity	<ul style="list-style-type: none"> <li>The AER’s starting point is the standard SL CAPM – its ‘Foundation Model’. Value of certain parameters and overall rate of return on equity estimate informed by considering other models and relevant data/evidence</li> <li>Estimate to be applied for the duration of the regulatory control period</li> </ul>	<p>Ergon Energy has departed from the AER’s Rate of Return Guideline on the choice of model. We consider that the application of the SL CAPM as set out in the Rate of Return Guideline will not produce a return on equity estimate that satisfies the requirements of the NER and the allowed rate of return objective.</p> <p>Instead, it is proposed that these requirements would be satisfied by estimating the return on equity by applying all relevant models (the SL CAPM, Black CAPM, Dividend Discount Model and Fama-French model), as permitted under the NER.</p>
Return on Equity: Risk free rate	<ul style="list-style-type: none"> <li>Observed yield on 10 year Commonwealth Government bonds</li> <li>Averaged over a 20 business day period, where the period is nominated in advance by the AER and will be as close as practicably possible to the commencement of the regulatory control period</li> </ul>	Ergon Energy’s proposed approach complies with the AER’s Rate of Return Guideline.
Return on Equity: Market Risk Premium	<ul style="list-style-type: none"> <li>10 year forward looking estimate commensurate with prevailing conditions in the market for funds at the commencement of the regulatory control period</li> <li>Evidence to be considered includes historical excess returns, dividend growth model, survey evidence, implied volatility and recent</li> </ul>	Ergon Energy continues to depart from the AER’s Rate of Return Guideline.

<sup>158</sup> Using the methodology specified in clause 6.5.2(j)(2) of the NER – known as the trailing average portfolio approach – the rate of return on debt, and consequently the allowed rate of return, will vary during each regulatory year of the regulatory control period 2015-20.

Allowed rate of return component / parameter	Rate of Return Guideline approach/value	Ergon Energy's proposal and identified departures
	regulatory determinations	
Return on Equity: Equity beta	<ul style="list-style-type: none"> <li>To be estimated using empirical analysis, which focuses on a small sample of domestic energy network businesses</li> <li>International comparators and the Black CAPM will inform where the point estimate is selected from within the range</li> <li>The AER's preferred value is 0.7.</li> </ul>	Ergon Energy continues to depart from the AER's Rate of Return Guideline
Rate of return on debt	<ul style="list-style-type: none"> <li>BBB+ credit rating assumption</li> <li>Based on historical trailing average portfolio approach, assuming one-tenth of the debt portfolio is refinanced each year (simple averaging approach)</li> <li>Transitional formula will apply for the first ten years</li> <li>Data used to produce the estimate will be sourced from an independent third party provider</li> <li>Measured using an averaging period of 10 or more consecutive business days and no more than twelve months. Averaging periods must be nominated by the NSP at the start of the regulatory control period</li> </ul>	<p>Ergon Energy has complied with the Rate of Return Guideline in estimating the return on debt in relation to:</p> <ul style="list-style-type: none"> <li>use of an independent third party provider to estimate the return on debt</li> <li>nomination of our proposed averaging periods for each year of the regulatory control period.</li> </ul> <p>Ergon Energy has departed from the Rate of Return Guideline in relation to the adoption of the trailing average approach, with a transition – Ergon Energy now proposes to adopt the <i>Hybrid</i> cost of debt approach based on the AER's determination of the efficient debt management strategy for the benchmark efficient business.</p> <p>Ergon Energy continues to depart from the Rate of Return Guideline in respect of:</p> <ul style="list-style-type: none"> <li><i>the notional credit rating assumption:</i> the AER's BBB+ assumption</li> <li><i>the averaging approach:</i> instead of a simple average, Ergon Energy is proposing to apply a weighted average that reflects the approved capital expenditure and associated borrowing profile contained in the approved PTRM. This is because a simple average could still result in a material mismatch between the actual and allowed return on debt given the lumpy nature of an energy NSP's capital expenditure profile. This is not consistent with the NER requirements.</li> </ul> <p>Ergon Energy has used data from the RBA and the Bloomberg BVAL curve to estimate the swap risk premium consistent with the AER's simple averaging measurement approach in the Preliminary Determination.</p> <p>Ergon Energy has estimated the return on debt as the average of the 1-10 year swap rates published by the Australian Financial Markets Association plus the weighted</p>



Allowed rate of return component / parameter	Rate of Return Guideline approach/value	Ergon Energy's proposal and identified departures
		trailing average swap risk premium using a hybrid approach plus the cost of the swap transactions required to effect the transition from the AER's efficient hybrid debt management approach under the previous NER to the trailing average approach under the new NER. For the first year of the regulatory control period, this results in a return on debt estimate of 5.68% based on the agreed averaging period for the base risk free rate and the historical 10 year average cost for the swap risk premium.
Gearing ratio	<ul style="list-style-type: none"> <li>Based on benchmark gearing ratio of 60% (debt to total value)</li> </ul>	Ergon Energy has proposed the Rate of Return Guideline value of 60%.
Allowed rate of return	<ul style="list-style-type: none"> <li>Defined as a nominal vanilla Weighted Average Cost of Capital (WACC)</li> <li>To be estimated based on a weighted average of the point estimates of the rate of return on equity and the rate of return on debt, assuming a 60% gearing ratio</li> <li>To be updated annually each year for adjustments to the rate of return on debt</li> </ul>	<p>The return on equity has been estimated based on the four relevant models specified above. This results in an estimate rounded to the nearest one decimal place consistent with the PTRM, resulting in an input value of 10.0%.</p> <p>Combining this with the return on debt of 5.68%, Ergon Energy's proposed WACC is 7.41% (post tax nominal vanilla).</p>
Imputation credits	<ul style="list-style-type: none"> <li>Value of 0.5 assigned to imputation credits</li> </ul>	Ergon Energy has departed from the AER's Rate of Return Guideline because we consider that there are a number of material flaws in the AER's reasoning and approach. Ergon Energy has proposed a value of 0.25, which we consider will better meet the requirements of the NER.

### 3 Proposed return on equity

We remain of the view that the approach to establishing the allowed return on equity that was set out in our October Regulatory Proposal is correct and a materially preferable approach to that which appears in the Preliminary Determination. Indeed it is necessary for the Preliminary Determination to be revoked and substituted in this respect for the final decision to accord with the allowed rate of return objective in the NEL.

#### 3.1 The evidence base upon which our submission is based

Ergon Energy jointly commissioned SFG Consulting (SFG) to undertake extensive analysis of the methods used to estimate the return on equity within the context of the NER requirements. The outcomes are summarised in SFG's summary report, *The Required Return on Equity for Regulated*

*Gas and Electricity Network Businesses* (the SFG Cost of Equity Report), which forms part of this Regulatory Proposal.<sup>159</sup>

SFG concluded that there is a broad range of evidence that is relevant to the estimation of the required return on equity for the benchmark efficient entity. In particular, four models are proposed as relevant evidence. SFG analyses this evidence, along with the relevant strengths and weaknesses. The relevant methods and models are used in estimating the return on equity, having regard to prevailing conditions in the market for equity funds.

The analysis by SFG demonstrates that the return on equity that would result if the Rate of Return Guideline was applied is too low and is well below the estimates produced by applying other relevant models and evidence.

Although the AER was not persuaded by the original expert reports that we submitted in support of our proposal, they should be reconsidered by the AER before making the Substitute Determination for our business because they provide a thorough analysis of why the 'multi-model' approach is preferable to the 'foundation model' approach. In many cases the AER has not properly recognised the insights models other than the SL CAPM provide into equity markets and the flaws those models reveal in the AER's approach.

Since the October Regulatory Proposal and before the Preliminary Determination was published, Ergon Energy jointly procured the following additional reports that support the original proposal, including:

- NERA – Review of the Literature in Support of the Sharpe-Lintner CAPM; the Black CAPM and the Fama-French Three-Factor Model (March 2015)
- SFG Consulting – The foundation model approach of the Australian Energy Regulator to estimating the cost of equity (March 2015)
- SFG Consulting – The required return on equity for the benchmark efficient entity (February 2015)
- NERA – Historical Estimates of the Market Risk Premium (February 2015)
- NERA – Empirical Performance of the Sharpe-Lintner and Black CAPM (February 2015)
- SFG Consulting – Beta and the Black Capital Asset Pricing Model (13 February 2015)
- SFG Consulting – Using the Fama-French model to estimate the required return on equity (February 2015)
- SFG Consulting – Share prices, the dividend discount model and the cost of equity for the market and a benchmark energy network (18 February 2015)
- Incenta Economic Consulting – Further update on the required return on equity from Independent expert reports (February 2015).

These reports were lodged by other businesses and Ergon Energy with the AER prior to the Preliminary Determination and Ergon Energy also requested that the AER consider many of these reports in our various submissions to the AER as part of our reset process but they have not yet formed a formal part of our submissions.

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<sup>159</sup> 08.01.01 — SFG Consulting: *The Required Return on Equity for Regulated Gas and Electricity Network Businesses*. The SFG Cost of Equity Report issued in May 2014 has been updated to reflect more up-to-date market parameters. The addendum, 08.01.02 – (Revised) *Frontier Economics: Addendum to Cost of Equity Report*, is also attached to this Regulatory Proposal.

For the purposes of our revised Regulatory Proposal, we have procured a number of additional reports and have included these documents as part of our documentation suite. We have relied on these reports in revising our proposal and responding to the AER's preliminary decision on the rate of return and gamma. Details of our response and the associated evidence can be found in the following response documents:

- *Rate of Return (Cost of Equity) – Response*
- *Rate of Return (Cost of Debt) – Response*
- *Value of Imputation Credits – Response.*

### **3.2 Our reasons for departure are enhanced by the additional evidence**

Our supporting submission, *Rate of Return (Cost of Equity) – Response*, summarises the additional evidence relied upon by us to support the necessary move away from the sole or predominant reliance on the SL CAPM when setting our allowed rate of return for equity. There is extensive support for the use of each of the dividend growth model/discounted cash flow, Black CAPM and Fama-French Three Factor Model concurrently with the SL CAPM.

For the reasons outlined in this appendix and our supporting submission, and the evidence underpinning those submissions, we do not consider there to be any concrete reason to depart from our October Regulatory Proposal in respect of the determination of the cost of equity. When the Preliminary Determination is revoked and substituted with the Substitute Determination, that determination should employ SFG's multi-model approach as we initially proposed.

Our supporting document emphasises the need for the AER to engage as part of the revoking and substitution process with material presented by us which demonstrates:

- The AER is required to, but has not, compared the outcomes of its decision-making process against returns currently observable in the financial market to ensure it is compensating us for the efficient financing costs of the benchmark entity.
- The AER's foundation model approach departs from the requirements of the NER in that it imposes restrictive constraints that effectively prohibit other evidence from affecting the allowed rate of return.
- The conclusions of the AER and its expert regarding the dividend growth model or discounted cash flow approaches being new models with no widespread use and acceptance are wrong and should be corrected.
- The AER has misunderstood how to assign a beta to an electricity network business with a 60:40 debt to equity capital structure facing the advent of disruptive technologies.
- The AER fails to take the necessary steps to address the downward bias in returns that the SL CAPM delivers for betas of below 1.
- Although the AER accepts the Fama-French model is "relevant", it excludes the model from its development of the allowed rate of return.

### **3.3 Other considerations – CCP**

In our meeting with CCP representatives in March 2014, Ergon Energy was requested to make some comparison between what current rates of return are being proposed and

- what is currently being considered by the Office of Gas and Electricity Markets

- what expected returns on equity are received by some of our customer groups.

Similar questions were raised with our customer representative groups in discussions with them as part of our regulatory proposal development process. We asked Synergies to look at the specific issues raised by the CCP and customers and their report forms part of our Regulatory Proposal.<sup>160</sup>

The Synergies report does indicate that the issues raised by the CCP and customers are not determinative in the setting of a forward-looking rate of return under the NER. Nevertheless, in our engagement with customers, the quantum of the rate of return and DNSP departures from the AER's Rate of Return Guideline were subject to criticism.

We have heard our customers and their disappointment with the quantum of the rate of return. We do note that market rates of return have improved since the time of our 2010-15 Distribution Determination and this has contributed to lower revenue requirements for the regulatory control period 2015-20. Changes to the NER also provide some comfort to customers that financing costs will be updated annually to reflect the most up to date market analysis.

Finally, we note at the beginning of this chapter that there are consequences for setting rates of return which are too low. The approach we have taken is focused toward long-term stability for customers and equity holders as well as debt financiers. It is also aimed at minimising short-term volatility in financial markets. We believe such an approach is consistent with customers' long-term interests and those of the financiers of regulated businesses.

### 3.4 Ergon Energy's proposed return on equity

Based on the evidence before us, updated for more recent market data, Ergon Energy's proposed return on equity is 10.04%,<sup>161</sup> as shown in Table 58.

**Table 58: Ergon Energy's proposed return on equity**

Model	Weighting	Return on equity
Sharpe-Lintner CAPM	12.50%	9.41%
Black CAPM	25.00%	10.02%
Fama-French	37.50%	10.02%
Dividend Discount Model	25.00%	10.39%
<b>Weighted average</b>		<b>10.04%</b>

Ergon Energy is submitting an estimate that makes appropriate use of all relevant models that have a role to play in informing the required return on equity in the current market and therefore satisfies the requirements of the NER, including satisfying the allowed rate of return objective.

If the AER continues to (incorrectly) limit its foundation model to the SL CAPM, it must apply a different approach to estimate that model than the approach set out in its Rate of Return Guideline. Ergon Energy's proposed alternative approach, which is set out in the SFG Cost of Equity Report,<sup>162</sup> and updated in its revised report, involves using all relevant models and evidence to estimate the parameters in the SL CAPM. This re-specified SL CAPM arrives at the same estimate as would result from the application of Ergon Energy's proposed multi-model approach.

<sup>160</sup> Refer to 08.01.04 – Synergies Economic Consulting: Response to Issues Raised by Consumer Challenge Panel.

<sup>161</sup> The calculated WACC is based on a rounded estimate of 10.00%, as per the PTRM.

<sup>162</sup> 08.01.01 – SFG Cost of Equity Report, p92.

## 4 Rate of return on debt

Like the return on equity, the return on debt must be estimated so that it contributes to the allowed rate of return objective.<sup>163</sup> The NER now permits an approach that could result in the return on debt changing in different regulatory years in the regulatory control period (or it could continue to be set for the entire period).<sup>164</sup>

The AER intends to transition NSPs from the current “on the day” approach to the trailing average portfolio approach over a period of 10 years. As a consequence, in the first regulatory year of the transitional period the allowed return on debt will be based on the estimated prevailing rate of return on debt for that year (consistent with the “on the day” approach), with prevailing rates in subsequent years progressively averaged in, with the prevailing rate in each year having a weight of 10%.

The transition to the trailing average method is without question the most significant issue concerning the debt allowance in this regulatory control period for our business.

Ergon Energy’s October Regulatory Proposal estimated the return on debt in a way that would comply with the AER’s Rate of Return Guideline in relation to the following areas:

- adoption of a ten year term to maturity
- adoption of the trailing average approach, with annual updates, which will be implemented over the ten year transition period
- the use of an independent third party data provider to estimate the return on debt.

We followed the AER’s Rate of Return Guideline in these respects because, at the time of our October Regulatory Proposal, this allowed Ergon Energy to recover a return on debt consistent with the allowed rate of return objective and the NER.

We departed from the AER’s Rate of Return Guideline in two areas where applying the Rate of Return Guideline would not have produced a return on debt consistent with the NER:

- the notional credit rating assumption (Ergon Energy proposed that this should be BBB)
- the weighting approach (Ergon Energy proposed that this should be a weighted average, based on changes in the PTRM debt balances).

However, since the time of our October Regulatory Proposal, further downward movements in base interest rates have further depressed the overall WACC and revealed errors in the AER’s approach on debt and, in particular, its approach to transition. The transition to a trailing average approach for the cost of debt leads to a mismatch between our regulated return and the efficient financing costs of a benchmark entity with a long-term staggered debt portfolio and base rate hedging (as acknowledged by the AER as the efficient approach to financing under the “on the day” method).

The mismatch arises because the AER’s transition applies an “on the day” debt benchmark at a time of record low interest rates to the majority of our debt throughout the regulatory control period 2015-20. This “on-the-day” debt benchmark will still contribute a 50% weight to our debt allowance at the commencement of the following regulatory control period when, in reality, the benchmark efficient debt was raised at higher costs.

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<sup>163</sup> NER, clause 6.5.2(h).

<sup>164</sup> NER, clause 6.5.2(i).

## 4.5 Revisions to our October Regulatory Proposal

Our revised Regulatory Proposal estimates the return on debt in a way that:

- maintains the position in our October Regulatory Proposal concerning consistency with the Rate of Return Guideline on:
  - adoption of a 10 year term to maturity
  - use of an independent third party data provider to estimate the return on debt
- maintains our departure from the Rate of Return Guideline concerning:
  - the notional credit rating assumption
  - the weighting approach
- departs from the Guideline and adopts the “hybrid” transition (also referred to as Option 3 in the AER’s Preliminary Determination).

## 4.6 The evidence base upon which our submission is based

Since the October Regulatory Proposal, we have observed developments in financial markets, and in the regulatory process. In response:

- TransGrid and Networks NSW have sought a cost of debt that applies no transition as they employed the trailing average approach under the previous NER. They have argued that the trailing average approach was the efficient approach for them – that their large size prevented them from adopting the hybrid approach because the swaps market is not sufficiently deep to meet their requirements.
- The AER has raised new matters in relation to the debt financing practices of the benchmark efficient entity. The new analysis and evidence referred to by the AER implies that there is no longer an appropriate basis for adopting the transitional arrangements set out in the Rate of Return Guideline and adopted by Ergon Energy in our October Regulatory Proposal.
- Jemena Gas Networks submitted changes to proposed approach to debt transition and included the following expert reports in support of its revisions:
  - Gray (SFG Consulting) – Return on debt transition arrangements under the NGR and NER (February 2015)
  - Hird and Young (CEG) – Critique of the AER’s JGN draft decision on the cost of debt (April 2015).
- After initially proposing an allowed return determined by gradually moving from the “on the day” method of determining debt to the trailing average method in a manner that was consistent with the AER’s Rate of Return Guideline, SA Power Networks advocated for a different approach. They considered establishing the allowed rate of return for debt commonly referred to as the “hybrid” approach would provide a transition path that a benchmark firm could in reality implement.<sup>165</sup>

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<sup>165</sup> SA Power Networks (2015), *SA Power Networks response to the AER’s Issues Paper: SA Power Networks electricity distribution regulatory proposal 2015-16 to 2019-20*, 30 January 2015, p10.



Additionally, the Queensland Treasury Corporation (QTC) has also provided us independent evidence in support of our preferred approach to calculating the cost of debt based on PTRM-weighting.<sup>166</sup>

#### 4.7 Our reasons for departure are enhanced by the additional evidence

Our supporting submission, *Rate of Return (Cost of Debt) – Response*, summarises the additional evidence supporting the necessary move away from the AER’s Rate of Return Guideline when calculating the return on debt. Our decision to revise our approach follows new evidence provided by the AER and other NSPs in recent regulatory determination processes, and advice obtained from Frontier Economics<sup>167</sup> and QTC.<sup>168</sup>

The AER’s Preliminary Determination in respect of debt applies the Rate of Return Guideline in full and imposes substantially lower allowances than any market-based measure of the costs of a benchmark network business implementing efficient financing practices.

For the reasons outlined in this appendix and our supporting submission and the evidence underpinning those submissions, there are no concrete reasons why we should change our view on the departures we proposed in the October Regulatory Proposal in relation to the cost of debt. On the evidence before us, we consider there is reason to further depart from the AER’s Rate of Return Guideline in relation to the approach to transition. These departures should be made when the Preliminary Determination is revoked and substituted with the Substitute Determination.

Our supporting submission emphasises that as part of the revoking and substitution process there is a need for the AER to properly engage with material presented by us which demonstrates:

- The AER’s approach to transition leads to a mismatch between the permitted return and the actual costs of a long-term staggered debt portfolio and base rate hedging that the AER has acknowledged to be the efficient approach to financing under the “on the day” method.
- The AER’s transition effectively substitutes an “on the day” debt benchmark taken at a time of record low interest rates for the actual efficient costs of a benchmark efficient firm.
- The AER proposes to set an allowed rate of return during the regulatory control period that effectively and incorrectly starts the regulatory control period with another 100% “on the day” allowance that will only progressively be replaced over the next 10 years.
- There is no correct basis to “carry over” alleged windfall gains or losses from any previous regulatory control periods when applying the rate of return objective on a forward looking basis.
- On a proper assessment, Ergon Energy is under-compensated if the AER proceeds with a transition on the debt risk premium component of the return on debt in the regulatory control period 2015-20.
- Given there is no windfall gain or loss to be brought to account because it is both factually absent and legally impermissible, the only appropriate transition is one that approximates the actual transactions that an electricity network business would enter into to move from a

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<sup>166</sup> QTC – PTRM-weighted trailing average report.

<sup>167</sup> Frontier Economics – Cost of debt transition.

<sup>168</sup> QTC – Return on debt transition analysis.



staggered long-term debt portfolio with base rate hedging to the long-term position in which the hedging component is progressively unwound.

- Our proposed PTRM-weighted trailing average correctly compensates a NSP who considers the prevailing cost of debt to be fairly priced when planned capital expenditure is undertaken, which is reasonable in an efficient market.
- The benchmark credit rating should be set having regard to the median over a period that appropriately balances the need for contemporaneous data but long enough for small short-term credit ratings movements not to affect the benchmark.

## 4.8 Other Issues

### Nomination of future averaging periods

While Ergon Energy has concerns with the requirement to nominate averaging periods for the remaining four years of the regulatory control period so far in advance, the possibility that the AER will impose these future averaging periods could present significant issues for how Ergon Energy manages our future funding and refinancing activities. Nevertheless, as indicated in our Framework and Approach submission, Ergon Energy's proposed averaging periods for the remaining years of the regulatory control period 2015-20 were included in our October Regulatory Proposal.<sup>169</sup>

### Summary of the methodology applied to estimate the proposed return on debt

Our October Regulatory Proposal summarised the approach that Ergon Energy applied to estimate the return on debt. For details of the calculation please refer to *08.01.11 – QTC: Extrapolating the RBA BBB curve to a 10-year tenor*. We still maintain this is a preferable approach. However, we have used the method outlined in the AER's Preliminary Determination for deriving a 10 year benchmark from data of shorter tenors. We reserve the right to revisit the choice of methodology in future regulatory determination processes.

### 4.9 Proposed return on debt

Application of the above approach results in a return on debt estimate of 5.68%, comprising a base swap rate of 2.92% and a swap risk premium of 2.53% plus swap transaction costs of 0.23%. Ergon Energy proposes that this approach results in the best estimate of the return on debt having regard to the requirements of the NER, including satisfying the allowed rate of return objective.

### 4.10 Equity raising costs

Ergon Energy proposes equity raising costs of \$1.74 million (in real \$2014-15). Equity raising costs have been included in the forecast capital expenditure in 2015-16 and have been calculated using the methodology embodied within the AER's PTRM.

## 5 Gearing

The NER require that the allowed rate of return be calculated as a weighted average of the return on equity and the return on debt for each regulatory year. The gearing ratio reflects the weight that is assigned to the return on debt.

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<sup>169</sup> Refer to Ergon Energy's supporting document *08.02.04 – Proposed Averaging Period for the Cost of Debt*.

The AER's Rate of Return Guideline specifies a preferred value of 60% for the gearing ratio. Ergon Energy has adopted a gearing of 60%.

## 6 Imputation credits

Ergon Energy proposes a gamma of 0.25, which reflects a distribution rate of 0.7 and theta of 0.35. This was the position adopted in the October Regulatory Proposal. We remain of the view that the approach to determining gamma set out in our October Regulatory Proposal is correct.

The gamma determined in the AER's Preliminary Determination is erroneous and needs to be revoked and substituted in the Substitute Determination by a figure of 0.25 in order to comply with the NER.

### 6.1 The evidence base for our submission

There is broad consensus among NSPs in relation to gamma. The same supporting materials and submissions presented by Ergon Energy have also been presented to the AER at the same time by other NSPs. Ergon Energy and other NSPs jointly commissioned a report from SFG Consulting on the value of gamma.<sup>170</sup> The purpose of this analysis was to obtain the best estimate for gamma at the current time, having regard to the requirements of the NER. The analysis draws upon the Tribunal's findings on gamma as part of the appeal submitted by Ergon Energy, Energex and (now) SA Power Networks.<sup>171</sup>

In the Preliminary Determination, the AER notes that in addition to the material that we submitted with our October Regulatory Proposal, there have been two additional reports jointly commissioned by Ergon Energy and a range of other NSPs. These are:

- *SFG Consulting – Estimating gamma for regulatory purposes*<sup>172</sup>
- *NERA – Distribution and redemption rates from taxation statistics*.<sup>173</sup>

In our view, the existing body of empirical work thoroughly supports a figure of no more than 0.25 and we do not propose to submit any new studies at this time. However, we are concerned that the AER's Preliminary Determination has not properly addressed the points that our experts and its own have made. Consequently, we have asked Gray and Hall to prepare a report that revisits key aspects of the existing materials and which collates the various ways in which the body of evidence contradicts the AER's gamma estimate of 0.4. This report, *Frontier Economics – An appropriate regulatory estimate of gamma*,<sup>174</sup> is lodged with our submission.

### 6.2 Evidence continues to support Ergon Energy's proposal

Our supporting submission, *Value of Imputation Credits – Response*, summarises the additional evidence supporting the value of gamma that Ergon Energy adopted in our October Regulatory Proposal.

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<sup>170</sup> 08.01.03 – *SFG Consulting: An Appropriate Regulatory Estimate of Gamma (SFG Gamma Report)*.

<sup>171</sup> Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9.

<sup>172</sup> SFG Consulting (2015), *Estimating gamma for regulatory purposes*, 6 February 2015.

<sup>173</sup> NERA (2015), *Estimating Distribution and Redemption Rates from Taxation Statistics*, March 2015.

<sup>174</sup> Frontier Economics (2015), *An appropriate regulatory estimate for gamma*, June 2015.

That document provides a clear foundation for the AER, when revoking and substituting the Substitute Determination in place of the Preliminary Determination, to replace the gamma of 0.4 with a gamma of no more than 0.25 because:

- The AER has used estimates of the utilisation rate produced by the equity ownership approach without making adjustments for the fact that simplifying assumptions underlying that approach do not hold in practice.
- The AER has used estimates of the utilisation rate produced by taxation statistics to support a value for the utilisation rate at the lower end of the range suggested by the equity ownership approach when the evidence before the AER is that the taxation statistics are an upper bound on the utilisation rate.
- The NER require gamma be a market based value.
- Gray and Hall's robust dividend drop-off studies deliver a value for theta of 0.35.
- The AER's criticisms and adjustments to Gray and Hall's work are unfounded.
- Gray, Hall and NERA agree that amongst different market valuation methods, dividend drop-off studies tend to give high values for gamma.
- The AER's partial reliance on distribution rates of 80% is inconsistent with its conception of the benchmark firm and each of the legitimate measures is approximately 70%.
- Combining a theta of 0.35 with a distribution rate of 70% gives a gamma of 0.25.

## **7 Materially Preferable NEO Decision**

It is essential that electricity NSPs are permitted to earn a fair market return at all times in order to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity. If a fair return is not permitted, the business cannot attract the equity investments needed to maintain assets and replace them when required.

In the short-term, no discernible difference in service may be observed because investment decisions are made for the long-term. However, in the short-term incentives arise to delay replacement investments or efficient capital augmentations and instead to continue to rely on the existing assets beyond when they should be most efficiently replaced.

In the longer term, if regulatory determinations were to persist with providing inadequate returns for more than a single five year regulatory control period, and if investors responded by refusing to provide any further equity injections when capital was needed (as they might reasonably do), NSPs may be required to take on a higher leverage putting the whole business at a higher risk of long run financial failure.

Financial failures are, of course, a very low probability but high risk consequence event for consumers and other end users – even when considered over a long-term horizon. Nevertheless, a significantly below market return during the current five year regulatory control period, would negatively affect investors (debt and equity) perception of the sovereign risk of investing. This would raise the long-term revenue expectations when investing to the long-term detriment of consumers across the NEM.

For the reasons explained in our submission, the Preliminary Determination did not provide a fair rate of return for the capital invested. The below market equity allowance arises from the use of the systematically downwardly biased SL CAPM, exacerbated by its 1:1 relationship with base

interest rates (which over the period of the NEM are at an all-time low), to constrain the contribution made by all the other available models. All those models deliver higher returns on equity.

As Gray and Hall's report on gamma explains, the level of gamma significantly affects the returns that investors received and it is essential that electricity NSPs are permitted to earn a fair market return at all times in order to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity. For the reasons explained above and in our submission, a gamma of 0.4 will not deliver a fair rate of return for the capital invested.

Additionally, as explained above, the AER has failed to provide an adequate risk adjusted return in the face of the rapid uptake of disruptive technologies.

The Preliminary Determination's debt allowance is also inadequate particularly because of the inappropriate transitional arrangements accompanying the introduction of the trailing average. The short-fall in the debt allowance is borne by equity holders because debt holders take a fixed market return regardless of the below-market regulatory allowance.

Each of the above errors in the Preliminary Determination (i.e. the use of the foundation model, the failure to take adequate account of other models, inadequate returns in the face of low base interest rates, a failure to compensate for the risk of disruptive technologies and the inadequate debt allowance) taken separately or combined, put unacceptable stress on our ability to raise equity and undermine our ability to invest for the long-term. Unless these flaws are rectified, end customers of electricity would ultimately bare the ill effects.

Further, we are concerned that the approach in the Preliminary Determination leads to excess volatility in returns which will send confusing investment signals to end consumers. As we have explained, the AER's SL CAPM is delivering unprecedented depressed returns due to the link with very low base interest rates. The transition path to the 10 year trailing average also initially locks in unprecedented low interest rates by applying a 100% weighting to the "on the day" method in the first regulatory year at a time when interest rates are at a record low and only very slowly reducing that proportion.

This approach to setting the equity and debt allowances will result in very substantial increases as the interest rate cycle turns. When interest rates are at above average levels, this will flow through to equity and debt allowances, which could (but for the low beta bias of the SL CAPM) tend to result in permitted revenues rocketing upwards and over-stimulating network investments.

Individual households are unlikely to be in a good position to make long-term cost-benefit assessments and speculative property developers do not have incentives to take long-term perspectives. Where regulated returns are inappropriately volatile, at high points in prices there is a significant risk that inefficient levels of disconnection could be "kick started". Above efficient levels of disconnection are to the detriment of both those who disconnect (and are then left with long run investments in battery storage and PV panels to pay-off even when network prices reduce again) and there is also significant detriment to those who remain connected and must bear the costs of stranded assets.

## 8 Supporting documentation

The following documents referenced in this appendix accompany our Regulatory Proposal:

Name	Ref	File name
An Overview, Our Regulatory Proposal 2015-20	0A.00.01	An Overview Our Regulatory Proposal
SFG Consulting: The Required Return on Equity for Regulated Gas and Electricity Network Businesses (SFG Cost of Equity Report)	08.01.01	SFG Cost of Equity Report
(Revised) Frontier Economics: Addendum to Cost of Equity Report	08.01.02	(Revised) Frontier Economics: Addendum to Cost of Equity Report
SFG Consulting: An Appropriate Regulatory Estimate of Gamma	08.01.03	SFG Gamma Report
Synergies Economic Consulting: Response to Issues Raised by Consumer Challenge Panel	08.01.04	Synergies Response to Issues Raised by the CCP
QTC: Extrapolating the RBA BBB curve to a 10-year tenor	08.01.11	QTC Extrapolating the RBA Curve
Proposed Averaging Period on the Cost of Debt	08.02.04	Proposed Averaging Period for the Cost of Debt
CEG: Critique of the AER's JGN Draft Decision on the cost of debt	N/A	CEG: Critique of the AER's JGN Draft Decision on the cost of debt
Frontier: Review of the AER's conceptual analysis for equity beta	N/A	Frontier: Review of the AER's conceptual analysis for equity beta
Frontier: Cost of debt transition	N/A	Frontier: Cost of debt transition
Frontier: An appropriate regulatory estimate of gamma	N/A	Frontier: An appropriate regulatory estimate of gamma
Incenta: Further update on the required return on equity from independent expert reports	N/A	Incenta: Further update on the required return on equity from independent expert reports
NERA: Empirical performance of SL and Black CAPMs	N/A	NERA: Empirical performance of SL and Black CAPMs
NERA: Historical estimates of the market risk premium	N/A	NERA: Historical estimates of the market risk premium
NERA: Review of the Literature in support of the SL CAPM, the Black CAPM and the Fama-French Model	N/A	NERA: Review of the Literature in support of the SL CAPM, the Black CAPM and the Fama-French Model
NERA: Estimating Distribution and Redemption Rates from Taxation Statistics	N/A	NERA: Estimating Distribution and Redemption Rates from Taxation Statistics
QTC: PTRM-weighted trailing average report	N/A	QTC: PTRM-weighted trailing average report
QTC: Return on debt transition analysis	N/A	QTC: Return on debt transition analysis
SFG: Beta and Black CAPM	N/A	SFG: Beta and Black CAPM

Name	Ref	File name
SFG: Shared prices, the dividend discount model and the cost of equity for the market and a benchmark energy network	N/A	SFG: Shared prices, the dividend discount model and the cost of equity for the market and a benchmark energy network
SFG: The foundation model approach of the AER to estimating the cost of equity	N/A	SFG: The foundation model approach of the AER to estimating the cost of equity
SFG: The required return on equity for the benchmark efficient entity	N/A	SFG: The required return on equity for the benchmark efficient entity
SFG: Using the Fama-French model to estimate the required return on equity	N/A	SFG: Using the Fama-French model to estimate the required return on equity
SFG: Estimating gamma for regulatory purposes	N/A	SFG: Estimating gamma for regulatory purposes
Rate of Return (Cost of Equity) – Response	N/A	Ergon Energy – Rate of Return (Cost of Equity) – Response
Rate of Return (Cost of Debt) – Response	N/A	Ergon Energy – Rate of Return (Cost of Debt) – Response
Value of Imputation Credits – Response	N/A	Ergon Energy – Value of Imputation Credits – Response

Additional documentation supporting our revised Regulatory Proposal can also be found in our responses on equity, debt and the value of imputation credits.

# Appendix D: Connection Policy

## Introduction and summary of changes

Our Connection Policy sets out the connection services offered by Ergon Energy and how we determine the charges that are payable for those services.

Ergon Energy has revised our Connection Policy to reflect the AER's Preliminary Determination. We have also adopted the adjustment factors applied by the AER to the unit rates.

## Customer benefits

The Connection Policy is core to how we will play our part in powering the economy by making it easier to connect to the network.



## Appendix D: Proposed Connection Policy

### 1 Background

Clause 6.8.2(c)(5A) of the NER requires Ergon Energy to include our proposed Connection Policy as part of our Regulatory Proposal. The proposed Connection Policy covers the charges that retail customers or real estate developers are required to pay for connection services provided under Chapter 5A of the NER and the basis for determining those charges.

This will be the first time that Ergon Energy has submitted a Connection Policy to the AER for approval as transitional arrangements currently provide that Ergon Energy's existing (QCA-approved) Capital Contributions Policy is considered to be our Connection Policy. Those transitional arrangements cease at the commencement of the regulatory control period 2015-20 (i.e. 1 July 2015).

### 2 Proposed Connection Policy

Ergon Energy's proposed Connection Policy, which has been developed in accordance with the AER's Connection Charge Guidelines<sup>175</sup> and the connection charge principles in clause 5A.E.1 of the NER, 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. For example, this may cover extension work from a customer's premises to the existing network or any necessary upgrade to the network's capacity as a result of a customer's connection. A copy of Ergon Energy's proposed Connection Policy is provided in supporting document *09.01.01 – (Revised) Ergon Energy Connection Policy*.

#### 2.1 Summary of connection services and charges

Connection services encompass the services required to physically connect premises to the Ergon Energy distribution network. They generally include the design, construction and energisation of connection assets. In some circumstances, the new connection or connection alteration may require an augmentation of the distribution network to ensure that there is sufficient capacity to service the connection. The new connection or connection alteration may also require a network extension.

Ergon Energy proposes to provide connection applicants with either a:

- Basic Connection Offer, under the terms of our relevant Model Standing Offers
- Negotiated Connection Offer, where the terms and conditions will be negotiated with the connection applicant.

The type of connection offer made by Ergon Energy will depend on the nature of the connection and whether there is supply available. Ergon Energy has defined all connection services as either basic connection services or negotiated connection services. At this stage, we do not intend to define any connection services as standard connection services.

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<sup>175</sup> AER (2013), *Connection charge guidelines: under Chapter 5A of the National Electricity Rules, Final Decision*, 20 June 2013. Available at <http://www.aer.gov.au/sites/default/files/AER%20-%20connection%20charge%20guideline%20-%2020%20June%202012.pdf>.

The connection charges that a connection applicant may be required to pay are the sum of:

- fees and charges for connection services classified as Alternative Control Services
- capital contributions for network extensions and other augmentations or connection assets required to enable the connection to the distribution network
- charges payable to account for any reimbursement schemes.

The following table summarises the types of connection services and offers provided by Ergon Energy.

**Table 59: Connection offers**

Connection Group	Type of connection offer	Description
Small Customers	Basic (including Basic – Micro EG)	Offered where supply is available, no or minimal augmentation is required and maximum capacity is no greater than 80 amps per phase. Typically, these customers include residences and small businesses, temporary connections, and unmetered supply. Basic connections are exempt from paying capital contributions for network augmentations (other than network extensions).
	Negotiated	Offered if augmentation is required for a connection to a small customer, capacity exceeds 80 amps per phase, or if the connection applicant requests a negotiated connection offer. Connection applicants may be required to pay capital contributions for network extensions and other network augmentation.
Real estate developers	Negotiated	Offered for developers of subdivisions, commercial/industrial premises and multi-tenancy residential premises.
Major customer connections	Negotiated	Offered to customers with loads exceeding 1.5MVA or where power usage is typically above 4GWh per annum at a single site or embedded generation that is above 10kW on 1 phase or above 30kW on three phases. Major customer connections are not required to pay capital contributions for network augmentation.
Public Lighting	Negotiated	Connection charges for public lighting are incorporated into the daily rate for public lighting (see Chapter 5). Connection applicants may be required to pay capital contributions for network extensions and other network augmentation.

## 2.2 Capital contributions

A capital contribution for connection services may be required of customers in certain circumstances and are calculated on a case by case basis (pre-calculated capital contributions will not apply) in accordance with the formula set out in the AER’s Connection Charges Guideline.

When calculating the cost of capital contributions, Ergon Energy will apply unit rates for the average cost of network augmentation. The methodology underpinning the calculation of the unit rates is further described in supporting document *09.02.01 – (Revised) Unit Rates for Capital Contributions*.

Where incremental revenue on a connection asset is calculated for a business customer, Ergon Energy will assume a connection period of 15 years in most circumstances. However, Ergon Energy may apply an alternate connection period where 15 years is not a considered reasonable estimate of the duration of the connection.

Specific requirements differ for each type of connection and customer and are described in greater detail in *09.01.01 – (Revised) Ergon Energy Connection Policy*.

## 2.3 Exemptions

Capital contributions for network augmentation (other than a network extension) are not applicable where the:

- connection is made under the terms and conditions of a Basic Connection Offer
- maximum demand at the connection point is less than 10kVA on SWER lines or 80 amperes on 3 phase low voltage supply (the augmentation charge threshold)
- connection is defined as a major customer connection.

Ergon Energy notes the AER's Connection Charge Guidelines suggest a 25kVA threshold on SWER lines. However, Ergon Energy has applied a 10kVA threshold for the reasons outlined below.

Ergon Energy notes that cost is currently one of the most significant customer concerns regarding their electricity supply. With customer density on the SWER network so low, and the network forming such a large part of Ergon Energy's lines asset base, appropriately managing the cost implications of operating the SWER network are crucial to customer prices.

The minimum size distribution transformer we supply on the SWER network is 10kVA. A large expense for SWER connections is the cost for line construction which, due the sparse population density of many of the SWER areas, can be quite high due to the distance. If the network augmentation charge threshold were to be set at 25kVA, it could mean, for example, that Ergon Energy would have to build a 10km line extension for a 10kVA transformer to supply a bore pump which may be rated at 2kW, with no capital contribution from the customer. This is despite the incremental costs of the connection far exceeding the incremental revenue expected to be received from the new connection over the applicable pre-defined period.

Another issue for Ergon Energy if the network augmentation charge threshold were to be set at 25kVA, is that the threshold would constitute 12.5% of the rated capacity of a 200kVA SWER isolation transformer. While we do have isolation transformer stations with higher capacity, these are not constructed without in-depth engineering assessments and extensive other works such as voltage regulators and extra re-closers to safely access the larger capacity within our voltage limits. By reducing the network augmentation charge threshold to 10kVA, Ergon Energy will be better able to avoid the potential for high costs that would be necessary to address load creep.

## 2.4 Reimbursement schemes

Ergon Energy will apply a reimbursement scheme to certain network extensions, where a customer connects to a network extension originally paid for by another customer. Real estate developers may be entitled to access the scheme unless an alternative arrangement is agreed with Ergon Energy.

The contribution towards the reimbursement scheme will be determined based on the expected usage of the network extension by the subsequent customer and the remaining life of the network extension assets.

The principles and methodology underpinning the calculation of reimbursement scheme amounts is described in greater detail in *09.01.01 – (Revised) Ergon Energy Connection Policy*, Section 2.8.

## 2.5 Security fees

Where a network augmentation or connection asset augmentation is valued at more than \$10,000, security fees may be charged where Ergon Energy identifies a risk that the estimated incremental revenue from particular connection services will not be recovered. The amount of that security fee equates to an amount which is the lesser of the incremental revenue at risk of non-recovery or the incremental cost incurred by Ergon Energy. Security fees will be rebated annually.

Further details are contained in *09.01.01 – (Revised) Ergon Energy Connection Policy*, Section 7.1.

## 2.6 Prepayments

Ergon Energy may request upfront payment, subject to the limitations described in the Connection Charge Guidelines. Further details are contained in *09.01.01 – (Revised) Ergon Energy Connection Policy*, Section 7.2.

## 3 Supporting documentation

The following documents referenced in this appendix accompany our Regulatory Proposal:

Name	Ref	File name
(Revised) Ergon Energy Connection Policy	09.01.01	(Revised) Ergon Energy Connection Policy
(Revised) Unit Rates for Capital Contributions	09.02.01	(Revised) Unit Rates for Capital Contributions

# Appendix E:

## The need for a ‘transition path’ for operating and capital expenditure

### Introduction

We believe a 'transition path' is appropriate if the AER is to make a distribution determination that provides for significant cuts to existing levels of expenditure. The AER has the power (if not a duty) to incorporate a transition path that takes into account:

- the external cost inputs faced by Ergon Energy
- the prudent and efficient costs of reducing expenditure to the levels required by the AER.

### Customer benefits

In circumstances where the AER substitutes expenditure forecasts well below what is forecast, there should be allowance for the expenditure reductions needed to meet the forecast expenditure allowances, a realistic assessment of the input costs faced by Ergon Energy and prudent and efficient costs incurred in reducing expenditure.

## **Appendix E: The need for a 'transition path' for operating and capital expenditure**

### **1 Introduction**

In response to various requests from the AER to stakeholders to seek submissions from and to engage with stakeholders over the question of a 'transition path', in our submissions to the AER leading up to the Preliminary Determination, as well as our cross-submissions on the determinations made for DNSPs in NSW and the ACT, Ergon Energy argued that the relevant provisions of the NER require the AER to consider a 'transition path' if the AER was to make a distribution determination that provided for significant cuts to existing levels of expenditure.

These submissions were put to the AER in response to the draft determinations for NSW and the ACT which used a methodology that implied very large cuts in future operating and capital expenditure for Ergon Energy. The Preliminary Determination for Ergon Energy involved reductions in future operating and capital expenditure which, while not as large as those implied by the draft determinations for NSW and the ACT, are still substantial. In light of this, the issue of a transition path remains relevant and Ergon Energy notes that we sought to engage directly with the AER on a number of occasions on this issue ahead of receiving our Preliminary Determination.

We note the AER's view, in its Preliminary Determination, that it has no power to provide a transition path. As the AER is aware, this question is the subject of applications for merits and judicial review in NSW, the ACT and Queensland. Accordingly, Ergon Energy has addressed, in this revised Regulatory Proposal:

- (a) the AER's power to consider a transition path
- (b) the reasons why a transition path is appropriate
- (c) the transition path that should be provided.

### **2 The AER has the power to include a transition path**

The AER is required to approve expenditure allowances that satisfy the criteria in clauses 6.5.6(c) and 6.5.7(c) of the NER. These criteria require the expenditure allowances to reasonably reflect:

- (a) efficient costs
- (b) costs that would be incurred by a prudent service provider
- (c) a realistic expectation of the DNSP's demand forecasts and cost inputs.

In its Preliminary Determination, the AER stated:

- A transition path is unnecessary when the AER's allowance is sufficient to achieve the relevant objectives.
- If a transition is a 'premium' above the efficient costs that a prudent operator would require, the AER cannot include that premium in the estimate of total forecast expenditure that the AER is satisfied reasonably reflects the relevant criteria.
- Conversely, if a transition is included as part of an allowance that reasonably reflects the relevant criteria, no further premium is required or possible.

The AER, in determining its forecast expenditure allowances, has relied heavily upon its findings as to the efficiency of revealed costs in the previous period, particularly in relation to operating expenditure and recurrent capital expenditure. However, it is important that the AER does not equate (or confuse) the methodology it has seen fit to adopt with the requirements of the NER itself. The fact that a category of costs may exceed the expenditure that the AER considers efficient as a result of its benchmarking analysis does not mean that such costs are excluded by the expenditure criteria in clauses 6.5.6(c) and 6.5.7(c) of the NER. Each of the expenditure criteria must be given its full force and applied in approving expenditure forecasts. This necessarily permits consideration of costs that might not be captured under the AER's revealed costs approach.

In this context, Ergon Energy has two principal concerns about the AER's application of the expenditure criteria in clauses 6.5.6(c) and 6.5.7(c) of the NER.

First, the AER has interpreted the third criterion (realistic expectation of required cost inputs) so as to give it virtually no relevance in the assessment of expenditure allowances. In effect, the AER equates this criterion to 'efficient costs' (i.e. the AER views the costs that are relevant in satisfying the third criterion are those costs which the AER deems 'efficient'). The AER has, by this approach, conflated the first and third criteria in a manner not permitted by the NER.

Through the third expenditure criterion, the NER recognise the fact that different DNSPs can face different cost inputs, not because one is less efficient than the other, but because cost inputs are not uniform across the country. No matter how efficient Ergon Energy is (or will be on 1 July 2015), certain cost inputs (including labour rates, property costs, materials, and fuel etc.) will not change overnight, if at all.

Cost inputs faced by Ergon Energy can be realistic (and even efficient) even though they exceed the level which the AER believes to be efficient having regard to its benchmarking and other enquiries. The AER's refusal to countenance this possibility has been found once before to be an error. Ergon Energy is concerned that the AER is once again taking a similar, but incorrect, approach.

Second, the AER has failed to recognise that a prudent and efficient DNSP will enter into arrangements to procure goods and services which may involve costs if those arrangements are to be terminated or substantially varied. For example, the costs of employing a person will include costs to be incurred if that employee is to be made redundant. Additional costs may be incurred in the sale of a property, the early termination of a lease, or the termination or variation of other contractual obligations (including as a result of the loss of volume-related discounts on purchases). Every prudent and efficient firm enters into supply arrangements which will obligate it to pay such costs. They are not, by themselves, necessarily imprudent or inefficient.

The AER's response to this fact is two-fold:

- (a) these costs were inefficiently incurred
- (b) customers should not pay for NSPs to become more efficient.

Again, the AER appears to have equated its revealed costs approach to assessing forecast expenditure with the requirements of the NER themselves. The AER has found, applying its benchmarking, that certain costs should not have been incurred in the relevant base year (it has not said which costs, it is has simply found that overall levels of expenditure were too high). However, this is a finding made by the AER entirely with the benefit of hindsight. Ergon Energy has incurred obligations under a regulatory regime where we operate under expenditure



allowances and incentive schemes that reward efficient expenditure and penalise inefficient expenditure. For many years, the AER took the same view.

In this environment, Ergon Energy entered into arrangements in good faith to acquire labour, as well as certain goods and services, which included terms that would impose reasonable costs on Ergon Energy in the event of termination or variation. It is impossible for Ergon Energy to have known that the AER would, with the benefit of hindsight, find those costs to be inefficient or imprudent when compared to other DNSPs. It may be appropriate for the AER to find that those levels of expenditure should not be maintained (although we take issue with this elsewhere) but that does not justify a finding that these commitments were entered into imprudently or inefficiently, or that the cost of terminating them are themselves imprudent or inefficient. It is not a question of whether customers should pay for Ergon Energy to become more efficient, but rather whether a category of costs satisfies the expenditure criteria and should therefore be included in forecast expenditure allowances.

### **3 A transition path is appropriate**

For the reasons outlined above, Ergon Energy believes that the AER has the power (if not a duty) to incorporate a transition path that takes into account:

- (a) the external cost inputs faced by Ergon Energy
- (b) the prudent and efficient costs of reducing expenditure to the levels required by the AER.

The report by PwC (*PwC – Transitional allowance*) explains why it is appropriate that the AER should include such a transition path for Ergon Energy.

The AER claims that it does not prevent a DNSP from inefficient spending (including costs incurred under existing agreements), just that the DNSP may need to fund that expenditure elsewhere (e.g. through other efficiencies or lower dividends). This argument ignores the fact that DNSPs operate under incentive schemes that punish them for overspending against the AER's forecasts, even if they can fund that overspend elsewhere. For example, if a DNSP overspends against the AER's capital expenditure forecast, it faces the threat of the ex post exclusion of that overspend from the RAB, even if it has found that money by reducing dividends. The proposition that a DNSP is free to determine its own transition path is incorrect.

### **4 The transition path proposed by Ergon Energy**

In its earlier submissions to the AER, Ergon Energy focused our arguments on the AER's power, under the NER, to consider a transition path. Ergon Energy did not specify the type of path that would be appropriate, as we did not know what level of future operating and capital expenditure the AER would approve.

Ergon Energy sets out our calculations in *10.01.01 – Transitional path allowance (confidential)* of the transition path that we consider appropriate, based on:

- (a) the expenditure reductions needed to meet the forecast expenditure allowances approved by the AER in its Preliminary Determination (corrected, in the case of forecast capital expenditure, for the errors in the Preliminary Determination)
- (b) a realistic assessment of the cost inputs faced by Ergon Energy
- (c) the prudent and efficient costs that will be incurred by Ergon Energy in reducing expenditure to the extent required.

Obviously, if the expenditure allowances approved by the AER differ materially from the Preliminary Determination, the appropriate transition path may also vary. If it is the AER's intention to materially depart from the forecast allowances approved in its Preliminary Determination, we urge the AER to consult fully and properly with Ergon Energy to determine whether a modified transition path would be appropriate.

## 5 Supporting documentation

The following documents referenced in this appendix accompany our Regulatory Proposal:

Name	Ref	File name
Transitional path allowance	10.01.01	Transitional path allowance
PwC – Transitional allowance	N/A	PwC – Transitional allowance

# Appendix F: Approach to confidential information

## Introduction and summary of changes

Ergon Energy recognises the importance of our customers and other stakeholders having access to sufficient information to understand and assess our Regulatory Proposal, and how it may affect their interests. However, in limited cases, publishing certain information may be detrimental to Ergon Energy and our customers.

Accordingly, we have made a number of confidentiality claims in accordance with the AER's Confidentiality Guideline. These claims have been updated to reflect our revised documentation suite.

## Customer benefits

We have published all of the documents we see as valuable to our customers and other stakeholders on our website to make the information as accessible as we can.

We have limited our confidentiality claims to information that is truly confidential.

## Appendix F: Approach to confidential information

### 1 Background

Ergon Energy recognises the importance of stakeholders having access to sufficient information to understand and assess the substance of this Regulatory Proposal, including how it may affect their interests. In preparing this Regulatory Proposal, Ergon Energy has sought to balance disclosure with the need to appropriately maintain confidentiality over certain information (as recognised by the categories of confidential information listed in the AER's Confidentiality Guideline).

Clause 6.8.2(c)(6) of the NER allows Ergon Energy to nominate those sections of the Regulatory Proposal and any supporting documents we believe contain confidential information.

### 2 Confidentiality template

While there is no confidential information contained in this main proposal document, some of the information we have provided in our supporting documentation is information that Ergon Energy believes should be treated by the AER as confidential and not be published.

Ergon Energy has completed a confidentiality claim template for those documents that contain confidential information in accordance with the AER's Confidentiality Guideline (refer to 11.01.01 – *(Revised) Confidentiality Template*).

Our claims of confidentiality broadly relate to the following types of information:

- payments made to customer owned embedded generators
- manufacturer defects
- intellectual property
- information which is subject to legal professional privilege
- voltage issues
- labour rates and fleet rates used in Alternative Control Service pricing
- proposed averaging periods for estimating the prevailing rate of return on debt
- insurance and self-insurance.

Further information for each confidentiality claim, including reasons for the confidentiality claim, are provided in the template.

Consistent with the AER's Confidentiality Guideline, each document that contains confidential information has been marked as such and a public version provided.

### 3 Supporting documentation

The following documents referenced in this appendix accompany our Regulatory Proposal:

Name	Ref	File name
(Revised) Confidentiality Template	11.01.01	(Revised) Confidentiality template

## Glossary

ABS	Australian Bureau of Statistics
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARR	Annual Revenue Requirement
Augex	Augmentation expenditure
BST	Base step trend
CAM	Cost Allocation Method
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model
CCP	Consumer Challenge Panel
CESS	Capital Expenditure Sharing Scheme
CIA	Corporation Initiated Augmentation
CPI	Consumer Price Index
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DUOS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme
EDSD	Electricity Distribution and Service Delivery
EEQ	Ergon Energy Queensland Pty Ltd
EET	Ergon Energy Telecommunications Pty Ltd
EG	Embedded Generator
ENCAP	Electricity Network Capital Program
EO&O	Ergon Energy owned and operated public light
Ergon Energy	Ergon Energy Corporation Limited
FiT	Feed-in tariff
G&EO	Gifted and Ergon Energy operated public light
GST	Goods and Services Tax
IBT	Inclining Block Tariff
ICT	Information and Communication Technology
Incenta	Incenta Economic Consulting
LED	Light emitting diode
MSS	Minimum Service Standards
NEL	National Electricity Law

NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
NSP	Network Service Provider
NSW	New South Wales
NUOS	Network Use of System
Opex	Operating expenditure
PTRM	Post Tax Revenue Model
PV	Photovoltaic
QCA	Queensland Competition Authority
QTC	Queensland Treasury Corporation
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
Repex	Replacement expenditure
RFM	Roll Forward Model
RIN	Regulatory Information Notice
ROLR	Retailer of Last Resort
Rules	National Electricity Rules
SAC	Standard Asset Customer
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCS	Standard Control Service
SFG	SFG Consulting
SL CAPM	Sharpe-Lintner Capital Asset Pricing Model
SPARQ	SPARQ Solutions Pty Ltd
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
TOU	Time-of-Use
Tribunal	Australian Competition Tribunal
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital
WARL	Weighted Average Remaining Life

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