



Ergon Energy Regulatory Proposal 2015 to 2020

31 October 2014



Contents

Contents	2
1. Introduction	4
1.1 Overview of our Regulatory Proposal	4
1.2 Regulatory Proposal documentation.....	5
1.3 Ergon Energy as a business.....	7
1.4 Other relevant matters.....	7
1.5 Supporting documentation.....	10
2. Classification of services and control mechanisms	12
2.1 Background.....	12
2.2 Service classification	12
2.3 Control service mechanisms	14
2.4 Supporting documentation.....	15
3. Revenue building blocks for Standard Control Services	17
3.1 Background.....	17
3.2 Regulatory Asset Base.....	19
3.3 Return on capital	23
3.4 Return of capital (depreciation)	23
3.5 Operating expenditure.....	24
3.6 Corporate income tax	24
3.7 Revenue increments/decrements	24
3.8 Annual Revenue Requirement	27
3.9 X-factors.....	28
3.10 Applying 2015-20 incentive schemes	29
3.11 Supporting documentation.....	30
4. Controls on revenue and prices for Standard Control Services.....	32
4.1 Background.....	32
4.2 Application of the standard control formula.....	32
4.3 Pricing arrangements	34
4.4 Proposed pass through events.....	39
4.5 Contingent projects	39
4.6 Indicative prices	40
4.7 Supporting documentation.....	43

5. Alternative Control Services	45
5.1 Background.....	45
5.2 Form of control mechanism	45
5.3 Basis of the control mechanism.....	45
5.4 Formula for Alternative Control Services	46
5.5 Default Metering Services	47
5.6 Public Lighting Services	51
5.7 Other Alternative Control Services	57
5.8 Assigning customers to tariff classes.....	61
5.9 Supporting documentation.....	62
Appendix A: Operating expenditure forecast for Standard Control Services.....	64
Appendix B: Capital expenditure forecasts for Standard Control Services.....	87
Appendix C: Rate of Return	116
Appendix D: Proposed Connection Policy	152
Appendix E: Approach to confidential information	157
Glossary	158

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 2020.¹

Our proposal, and our overview of the proposal,² 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 Australian Energy Regulator (AER) to make the necessary decisions and determinations under the NER.

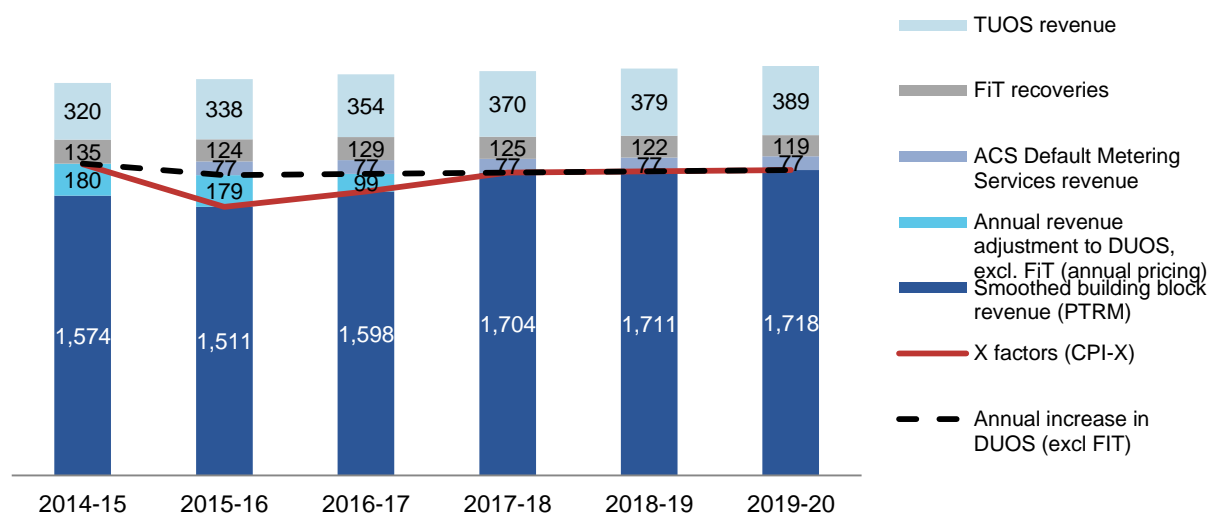
1.1 Overview of our Regulatory Proposal

For the next regulatory control period, Ergon Energy proposes:

- a nominal **decrease** in aggregate Distribution Use of System (DUOS) charges (excluding Solar Bonus Scheme feed-in tariff (FiT) costs) of **3.7% in 2015-16**
- annual changes in aggregate DUOS charges (excluding FiT) over the period that average less than inflation.

The following chart summarises the indicative movements in the aggregate network charges for the next regulatory control period, including annual increases in DUOS charges (excluding FiT) which represents the substance of our Regulatory Proposal.

Figure 1: Movement in aggregate expected network charges, 2014-20 (\$m, nominal)³



	2015-16	2016-17	2017-18	2018-19	2019-20
- - - Annual increase in DUOS (excl. FiT)	-3.7%	0.4%	0.4%	0.4%	0.4%
--- X Factors (CPI - X)	15.9%	-3.1%	-3.9%	2.1%	2.1%

¹ This proposed term is consistent with the length of the current regulatory control period and is the minimum duration for a regulatory control period permitted under clause 6.3.2(b) of the NER.

² 0A.00.01 – An Overview, Our Regulatory Proposal 2015-20

³ Revenue from Type 5 and 6 metering installation, provision, maintenance, reading and data services was previously included in DUOS in 2014-15. Since this service will be an Alternative Control Service in the next regulatory control period, revenue associated with this service has not been included in DUOS for 2015-20.

There have been substantial increases in the network component of customer electricity bills in the current regulatory control period 2010 to 2015. Through our engagement program, we have a clear understanding of the level of concern about rising electricity prices. Reducing what we charge for the use of the distribution network in 2015-16 and having increases over the next five years⁴ below the Consumer Price Index (CPI) 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 next regulatory control period is shown in Table 1 below.

Table 1: Historic and proposed increases to our revenue requirements and associated residential price impact⁵

\$ 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%	(6%)	(4%)	(1%)	(1%)	(1%)
\$ change	\$53	\$69	\$91	\$90	\$ (58)	\$ (36)	\$ (6)	\$ (10)	\$ (5)
Estimated impact of DUOS increase on retail bill	4%	5%	6%	5%	(3%)	(2%)	0%	(1%)	0%

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

- a new charge for Default Metering Services (Type 5 and 6 meters) in line with the AER's Framework and Approach Paper
- a nominal (and real) price decrease between 2014-15 and 2015-16 for Public Lighting Services,⁶ as well as a price path of CPI + 0.60% for the final four years of the period
- other user specific charges, which are proposed consistent with our approach in the current regulatory control period.

1.2 Regulatory Proposal documentation

The information requirements for our Regulatory Proposal are extensive.⁷ Our Regulatory Proposal therefore includes this main proposal document (including appendices), our overview and a series of supporting documents, attachments, models and referenced material which provide

⁴ Refers to price changes between 2014-15 and 2019-20.

⁵ 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. 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>.

⁶ This is based on a customer with a mix of 'Ergon Energy Owned & Operated' and 'Gifted & Ergon Energy Operated' public lights consistent with the overall inventory mix on Ergon Energy's network. Refer to Section 8.2 of 05.01.01 – Public Lighting Services Summary.

⁷ 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.

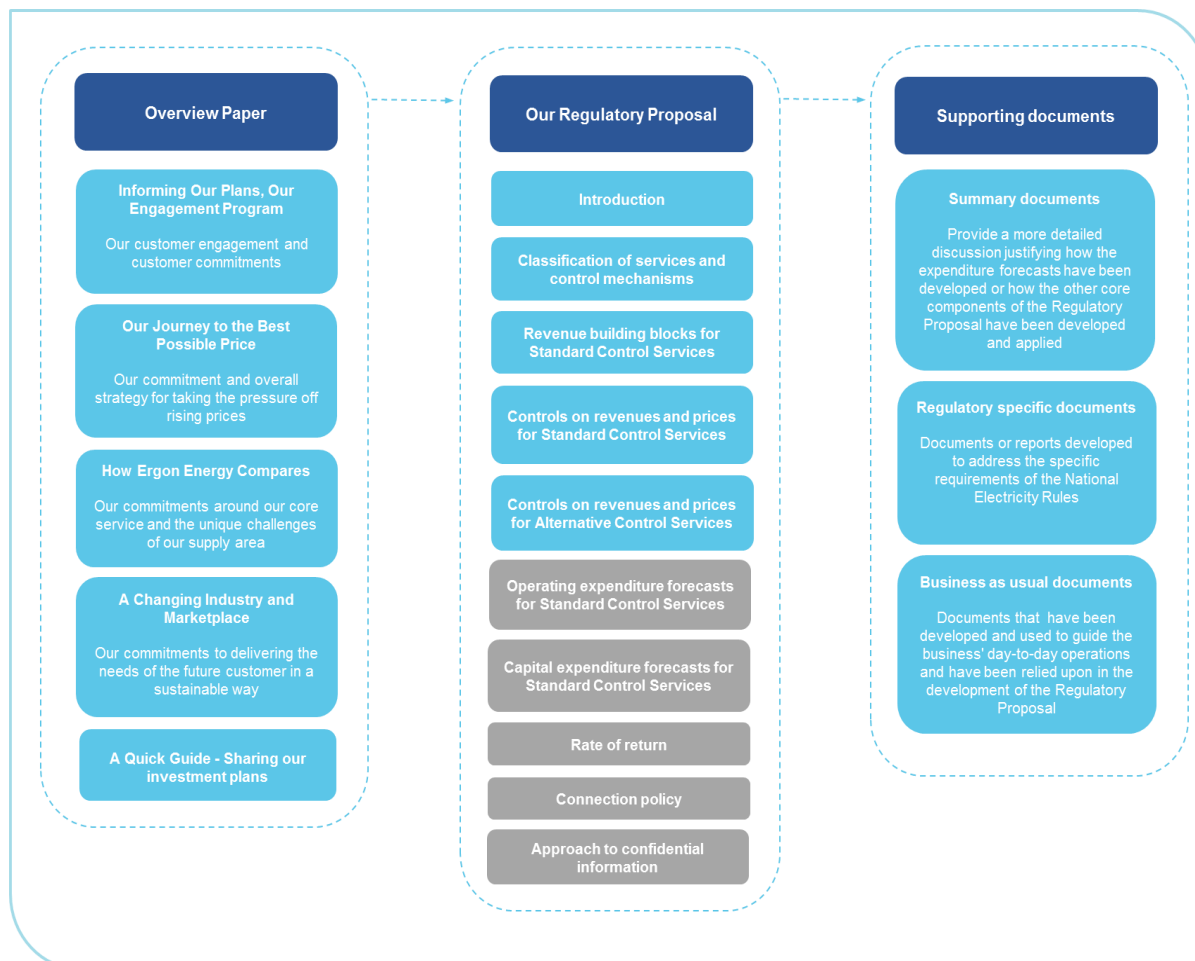
information addressing specific regulatory issues and requirements, business as usual policies, procedures and practices, and financial and regulatory models. Each of these documents should be considered by the AER in making its Distribution Determination.

Accompanying our Regulatory Proposal are the following documents:

- *An Overview, Our Regulatory Proposal 2015-20*,⁸ summarising key matters of importance to electricity consumers⁹
- 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.¹⁰ 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.

A graphical depiction of the suite of information prepared with our Regulatory Proposal is provided in Figure 2.

Figure 2: Overall structure of our Regulatory Proposal package



⁸ OA.00.01 – *An Overview, Our Regulatory Proposal 2015-20*

⁹ This includes the matters required under clause 6.8.2(c1) of the NER.

¹⁰ 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.

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.¹¹ Accordingly, Ergon Energy has included the Mount Isa–Cloncurry network in this Regulatory Proposal.¹² This is consistent with the approach adopted in the AER's Distribution Determination for the current regulatory control period 2010-15.

Ergon Energy has included a supporting document, *How Ergon Energy Compares*,¹³ 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

The Framework and Approach Paper 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.

¹¹ 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.

¹² 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.

¹³ Refer to *0A.01.01 – How Ergon Energy Compares*.

The AER issued the Framework and Approach Paper for Ergon Energy on 30 April 2014.¹⁴ Ergon Energy has taken the outcomes of the AER's Framework and Approach Paper into account in preparing this Regulatory Proposal.

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 Methodology¹⁵ 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.¹⁶

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 current regulatory control period

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 current regulatory control period and will cease to have effect in the next regulatory control period 2015-20. In addition, changes to the NER during the current regulatory control period resulted in a number of transitional arrangements which will also cease to have effect.

The transitional arrangements related to the following matters:

- the treatment of assets included in the Regulatory Asset Base (RAB)¹⁷
- Capital Contributions Policy and treatment of capital contributions in the RAB¹⁸
- Efficiency Benefit Sharing Scheme (EBSS)¹⁹
- Service Target Performance Incentive Scheme (STPIS)²⁰
- jurisdictional schemes²¹
- the recovery of charges for using the non-regulated 220 kV network which supplies the Cloncurry township²²
- the recovery of entry and exit charges relating to non-regulated connection points between Powerlink's transmission network and our distribution network.²³

¹⁴ Available at <http://www.aer.gov.au/node/20186>.

¹⁵ As required by clause 6.8.1A of the NER.

¹⁶ Refer to <https://www.ergon.com.au/network/network-management/future-investment/future-direction>.

¹⁷ NER, clause 11.16.3.

¹⁸ NER, clauses 11.16.10 and 11.46.6.

¹⁹ NER, clause 11.16.4.

²⁰ NER, clause 11.16.5.

²¹ NER, clause 11.35.

²² NER, clause 11.39.6.

²³ NER, clause 11.39.6.

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 – 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 next regulatory control period.

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 2015.²⁴

Because the Substitute Determination is made after the commencement of the next regulatory control period, adjustments may be necessary to account for changes between the Preliminary and Substitute Determination.²⁵

1.4.5 Legislative and regulatory obligations

Ergon Energy must comply with numerous legislative and regulatory obligations, and Queensland Government policy requirements, in the next regulatory control period. Some of these obligations directly impact our expenditure forecasts. Our supporting document *01.01.01– 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 outlined 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.²⁶

1.4.7 Negotiating framework

Neither the AER nor Ergon Energy have proposed that any services be classified as negotiated distribution services in the next regulatory control period. In its Framework and Approach 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.²⁷

²⁴ NER, clause 11.60.4(c).

²⁵ Our supporting document *04.01.00 – Compliance with Control Mechanisms* provides some detail on how this will apply.

²⁶ NER, clause 6.9.1.

²⁷ AER (2014a), *Final Framework and approach for Energex and Ergon Energy, Regulatory control period commencing 1 July 2015*, April 2014, p154.

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 E.

1.5 Supporting documentation

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

Name	Ref	File name
An Overview, Our Regulatory Proposal 2015-20	0A.00.01	An Overview Our Regulatory Proposal
Regulatory Information Notice	N/A	Our response to the AER’s RIN is contained in a number of files attached to this proposal
How Ergon Energy Compares	0A.01.01	How Ergon Energy Compares
Legislative and Regulatory Obligations and Policy Requirements	01.01.01	Legislative and Regulatory obligations
The Effect of Transitional Arrangements	01.01.02	Effect of Transitional Arrangements
Ergon Energy Negotiating Framework	01.01.03	Negotiating Framework
NER Compliance Matrix	01.02.01	Compliance checklist
Compliance with Control Mechanisms	04.01.00	Compliance with control mechanisms

Chapter 2: Classification of services and control mechanisms

Introduction

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.

Our proposal adopts the changes to the classification of services that were put forward by the AER for the next regulatory control period.

Customer benefits

Our best possible price commitment applies to our Standard Control Services. We're targeting to reduce what we charge for the use of our network in 2015-16, and keep increases overall in network charges under inflation for the next five years.

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 next regulatory control period 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.

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).

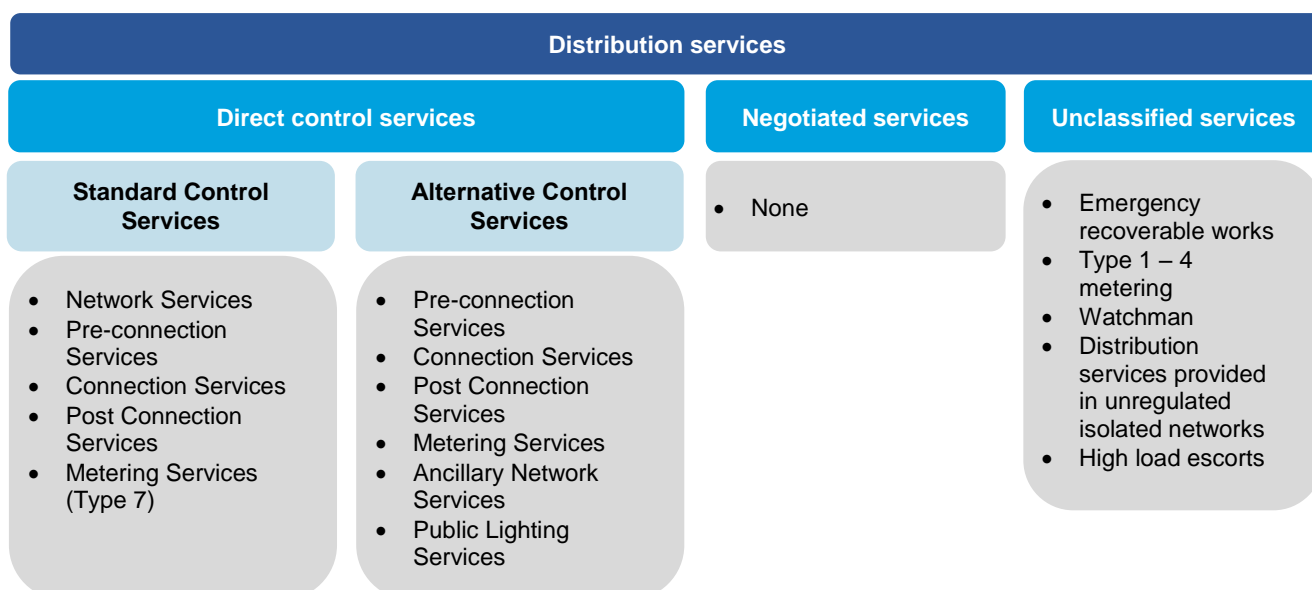
The classification that is applied to Ergon Energy’s Direct Control Services will have a direct bearing on whether the costs of the services are recovered from:

- 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 3 below.

Figure 3: 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 next regulatory control period. 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 next regulatory control period.

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 Classification proposal

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 Appendix B of its Framework and Approach Paper, 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 – Classification Proposal*. This document also provides our interpretation of how the AER’s classification of services will apply in practice in the next regulatory control period.

2.2.4 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, 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
Classification Proposal	02.01.01	Classification Proposal

Chapter 3: Revenue building blocks for Standard Control Services

Introduction

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.

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 as we move into the next period.

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.²⁸

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.²⁹

Ergon Energy has used a version of the PTRM developed by the AER in May 2014 that accounts for the changes resulting from the AER's Rate of Return Guideline. We have also populated the current version of the PTRM as issued by the AER in June 2008. Both PTRMs accompany our Regulatory Proposal.³⁰ Taken together, these two PTRMs allow Ergon Energy to comply with clause 6.3.1(c)(1) of the NER.

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.

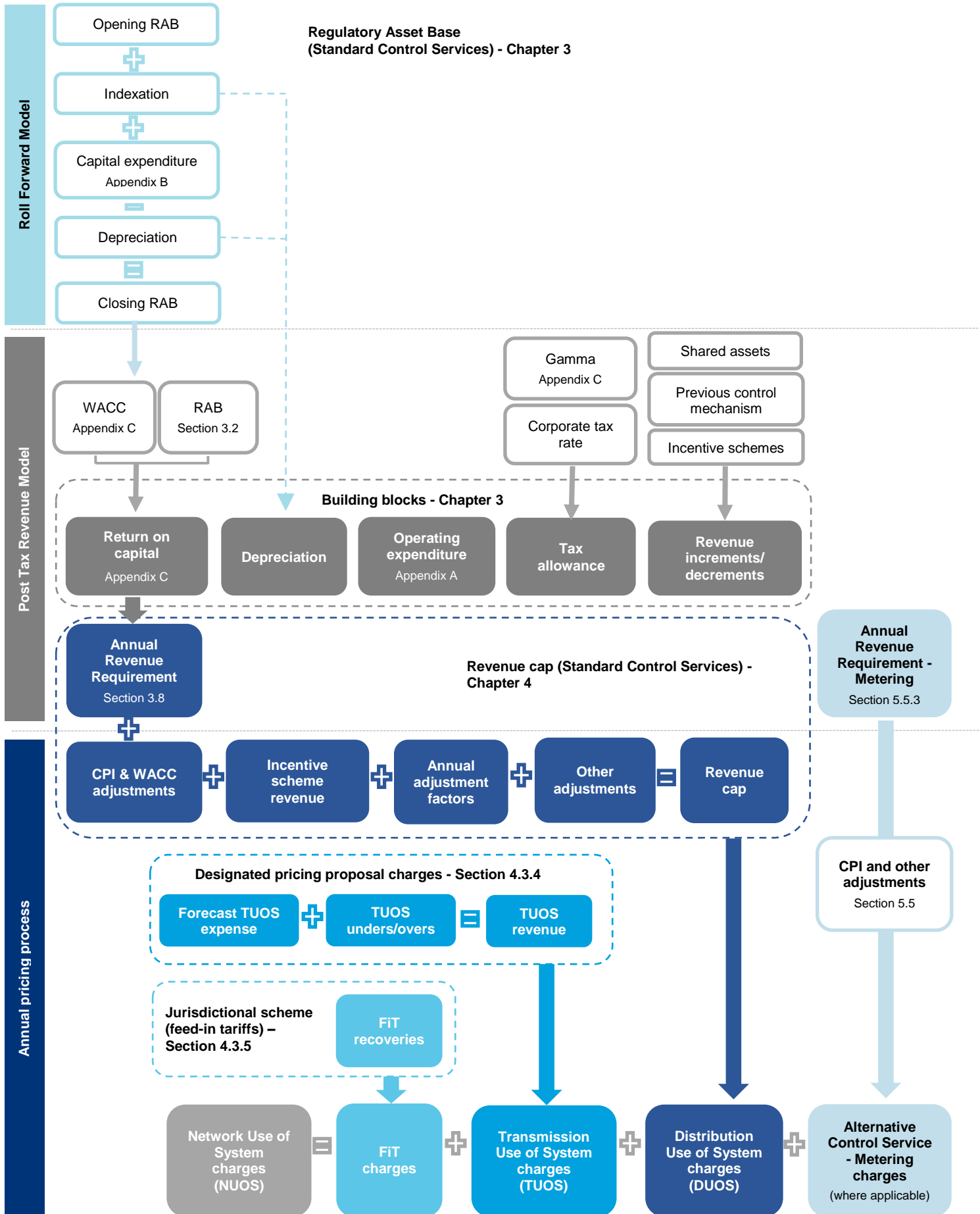
A graphical depiction of the building block approach and other components that are used in calculating the Network Use of System charge is contained in Figure 4. This diagram also shows where each component is addressed in our Regulatory Proposal.

²⁸ NER, clause 6.4.3.

²⁹ 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.

³⁰ Refer to 03.01.04 – Post Tax Revenue Model (May 2014) and 03.01.05 – Post Tax Revenue Model (June 2008).

Figure 4: Components of the network bill and this Regulatory Proposal



3.2 Regulatory Asset Base

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 next regulatory control period is shown in Table 3 below. This value has been derived by adjusting the value of the RAB at the beginning of first regulatory year of the current regulatory control period (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.³¹ 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 – Ergon Energy's building block components (Building Blocks supporting document)*.

³¹ NER, clause 11.16.3.

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

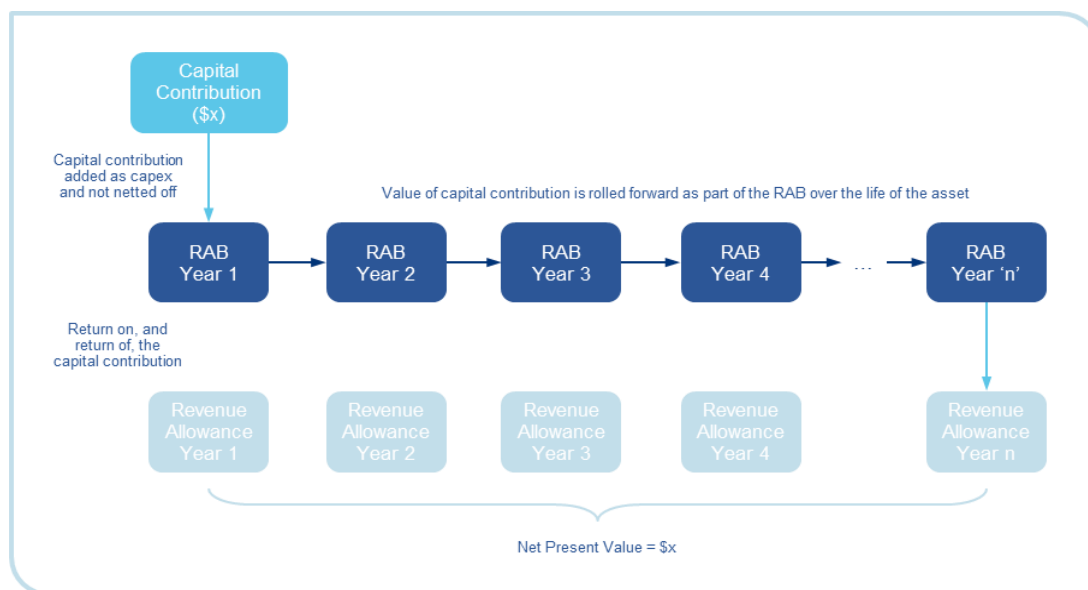
\$m (nominal)	2010-11 Actual	2011-12 Actual	2012-13 Actual	2013-14 Actual	2014-15 Estimate
Opening RAB	7,160.95	7,858.05	8,360.76	9,006.79	9,606.34
<i>plus</i> capital expenditure (net of disposals and capital contributions)	801.49	758.16	827.95	748.54	885.91
<i>less</i> regulatory depreciation	(104.39)	(255.46)	(181.92)	(148.99)	(186.67)
<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	-	-	-	-	(209.75)
Closing RAB	7,858.05	8,360.76	9,006.79	9,606.34	10,095.83
<i>less</i> adjustments to recognise changes in service classifications that occur on 1 July 2015	-	-	-	-	(54.29)
Opening RAB 1 July 2015					10,041.54

3.2.2 Capital Contributions

Under the transitional arrangements in clause 11.16.10 of the NER, the RAB that was used to determine the allowable revenue for the current regulatory control period 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 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 5.

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 current regulatory control period 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 5: Treatment of capital contributions under Chapter 11 of the NER



For the next regulatory control period, 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 capital contributions received during the next regulatory control period.

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	10,041.54	10,651.75	11,233.28	11,748.10	12,311.45
<i>plus</i> capital expenditure (net of disposals and capital contributions)	783.74	773.23	722.49	724.13	725.82
<i>less</i> regulatory depreciation	(173.53)	(191.70)	(207.66)	(160.77)	(170.28)
Closing RAB	10,651.75	11,233.28	11,748.10	12,311.45	12,867.00
Inflation rate	2.57%	2.57%	2.57%	2.57%	2.57%

Further details explaining the basis for the estimates of capital expenditure for the next regulatory control period 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:

- removal of assets that were (or will be) disposed during the regulatory control period 2010-15

- removal of assets from the RAB that will not be used to provide Standard Control Services in the next regulatory control period 2015-20
- inclusion of assets in the RAB that were previously unregulated, but which will be used to provide Standard Control Services in the next regulatory control period 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 current regulatory control period is based on the actual proceeds from sale, which is consistent with the approach used for forecasting disposals in the PTRM for the next regulatory control period.

Further details explaining the basis for the actual disposals recognised in the RFM for the current regulatory control period and the forecast disposals recognised in the PTRM for the next regulatory control period 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 next regulatory control period.

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*.

Inclusion of assets due to service reclassifications

Ergon Energy has a number of assets that were not included in the RAB for the current regulatory control period, but which have been (or will be) included in the RAB for the next regulatory control period.

Consistent with clause S6.2.1(e)(8) of the NER, these assets have been included in the RAB because:

- they were never previously used to provide Standard Control Services
- the value of the assets have not been recovered through network charges for Standard Control Services
- these assets will be used in the next regulatory control period for the provision of regulated distribution services and, more specifically, Standard Control Services, consistent with the AER's classification of services.

The written down values of the assets have been recognised as capital expenditure in the RFM in the financial year in which the reclassification occurred. The values were disaggregated into the Standard Control Service asset classes that most appropriately aligned with the type of assets being transferred into the RAB.

Further details of the increase to the RAB to recognise the reclassification of the services provided by these assets are also found in Chapter 2 of our *Building Blocks supporting document*.

3.3 Return on capital

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*”.³²

Ergon Energy has estimated an allowed rate of return of 8.02% 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 next regulatory control period, 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	804.93	853.84	900.46	941.73	986.89

3.4 Return of capital (depreciation)

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).

Our proposed regulatory depreciation for Standard Control Services for each year of the next regulatory control period 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	173.53	191.70	207.66	160.77	170.28

³² NER, clause 6.5.2(c).

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 standard life of the asset.

We have forecast our depreciation schedules by applying the AER's roll forward of the opening asset base and our forecast capital expenditure and disposals. A detailed explanation supporting the calculation of depreciation is provided in Chapter 4 of our *Building Blocks supporting document*. This supporting document also includes our estimates of the average standard and remaining lives of each asset class.

3.5 Operating expenditure

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	370.45	387.20	405.65	426.61	444.78

3.6 Corporate income tax

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 next regulatory control period 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	115.74	122.26	131.50	123.58	128.33

3.7 Revenue increments/decrements

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 next 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 current regulatory control period³³
- two incentive schemes:³⁴
 - EBSS
 - Demand Management Incentive Scheme (DMIS)³⁵
- the use of shared assets.³⁶

The revenue increments and decrements have been included in the PTRM as an individual line item within the operating expenditure input section, consistent with the approach noted in the PTRM Handbook.³⁷

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 Revenue³⁸ 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 this amount as a carry forward adjustment in the PTRM. Further information is contained in supporting document *03.01.02 – Other revenue adjustments*.

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

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 next regulatory control period relates to our performance under the EBSS in the current regulatory control period.

Ergon Energy underspent our operating expenditure forecast in the current regulatory control period (refer to Appendix A). This has resulted in an overall EBSS reward for Ergon Energy in the

³³ NER, clause 6.4.3(a)(6) – the application of the control mechanism in the current regulatory control period 2010-15.

³⁴ NER, clause 6.4.3(a)(5) – the application of incentive schemes (if any).

³⁵ NB – The NER has since changed the name of this scheme to 'Demand Management and Embedded Generation Connection Incentive Scheme' (DMEGCIS) 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.

³⁶ NER, clause 6.4.3(a)(6A).

³⁷ The PTRM Handbook states that any carry over amounts arising from the arrangements of the previous regulatory control period should be separately identified within the operating expenditure section of the PTRM input sheet.

³⁸ In the next regulatory control period, due to changes to the Standard Control Services formula, the Maximum Allowable Revenue will be referred to as the Total Allowed Revenue.

next regulatory control period 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 next regulatory control period 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 next regulatory control period (i.e. the Demand Management Innovation Allowance (DMIA)). Consistent with the Framework and Approach Paper, Ergon Energy has proposed a total DMIA allowance of \$5 million over the next regulatory control period. For revenue modelling purposes, Ergon Energy has included the \$5 million DMIA as a bottom up item in our operating expenditure forecast. To avoid double counting of the allowance, no further adjustments have been made to the revenue model.

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	37.54	55.09	79.67	(18.43)	0.00
DMIS (Part A, DMIA)	1.00	1.00	1.00	1.00	1.00

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

3.7.3 Shared assets

For the current 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 next regulatory control period.³⁹ This means the opening RAB value at 1 July 2015 contains values for assets that are used to provide Standard 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.

³⁹ 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.

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 – 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	(6.02)	(6.18)	(6.33)	(6.50)	(6.66)

3.8 Annual Revenue Requirement

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 in supporting document *03.01.04 – Post Tax Revenue Model*.

Table 11: Annual Revenue Requirement, 2015-20

\$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Return on capital	804.93	853.84	900.46	941.73	986.89
Return of capital	173.53	191.70	207.66	160.77	170.28
Operating expenditure	370.45	387.20	405.65	426.61	444.78
Corporate income tax	115.74	122.26	131.50	123.58	128.33
Other adjustments	90.08	48.92	73.34	(24.92)	(6.66)
Building Block Revenue (unsmoothed)	1,554.74	1,603.92	1,718.60	1,627.77	1,723.61
Annual Revenue Requirement (smoothed)	1,511.09	1,598.46	1,703.82	1,710.69	1,717.60

3.9 X-factors

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, our revenues are adjusted annually to incorporate a number of other revenue adjustments included in the Standard Control Services formula. For example, the Total Allowed Revenue in 2015-16 includes the smoothed ARR plus adjustments for:

- a financial reward for our performance under the STPIS in 2013-14
- a Solar Bonus Scheme cost pass through amount relating to FiT payments made in 2013-14
- any DUOS under or over-recovery amount from 2013-14
- any under or over-recoveries relating to capital contributions and shared assets from 2013-14.

The result of the magnitude of forecast adjustments in 2015-16 and 2016-17 mean that even if Ergon Energy targeted a reduction in ARR, customers could face increases in changes for those years. As noted in Chapter 1, through our engagement program we have a clear understanding of the level of concern about rising electricity prices and the traditional approach to calculating X-factors would result in unacceptable outcomes. As part of our customer commitments, we have therefore targeted smoothed ARR's (through X-factor adjustments) that allow a reduction in DUOS revenue (excluding FiT) in the first year.

Ergon Energy's proposed X-factors for Standard Control Services for each year of the next regulatory control period 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	15.85%	(3.13%)	(3.92%)	2.11%	2.11%

Ergon Energy has calculated the proposed X-factors for each year of the next regulatory control period 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's Framework and Approach Paper proposed to apply the following incentive schemes to Ergon Energy in the next regulatory control period:

- DMIS
- EBSS
- STPIS
- Capital Expenditure Sharing Scheme (CESS).

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 each scheme. However, 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 next regulatory control period 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 operation of the EBSS. Further detail is provided in our supporting document *03.01.03 – 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 next regulatory control period's EBSS and 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
EBSS	Revenue increment/decrement in the ARR calculation in 2020-25. There will be no revenue impact in 2015-20.	N/A
STPIS	Adjustment to the ARR 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
Ergon Energy's Building Block Components	03.01.01	Building Block Components
Other Revenue Adjustments	03.01.02	Other revenue adjustments
Application of Incentive Schemes	03.01.03	Ergon Energy Incentive Schemes
Post Tax Revenue Model (May 2014)	03.01.04	SCPTRM Data Model AER May 2014 Version
Post Tax Revenue Model (June 2008)	03.01.05	SCPTRM Data Model AER June 2008 Version
Roll Forward Model	03.01.06	SCRFM Data Model

Chapter 4:

Controls on revenue and prices for Standard Control Services

Introduction

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.

Customer benefits

In considering the pricing matters in this chapter we have looked to minimise price volatility where ever possible, deliver price relief at the beginning of the period and keep increases overall in network charges on average under inflation.

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,⁴⁰ including the form of the control mechanism⁴¹ and the X-factor⁴²
- how compliance with the control mechanism will be demonstrated⁴³
- how customers will be assigned to tariff classes and, if required, be re-assigned between tariff classes⁴⁴
- how designated pricing proposal charges (or Transmission Use of System (TUOS) charges) will be recovered, including any unders and overs adjustments⁴⁵
- how Ergon Energy will report on recovery of any jurisdictional scheme amounts, including any unders and overs adjustment for each scheme.⁴⁶

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 Framework and Approach Paper indicated that the Standard Control Services formula that would apply in the next regulatory control period would take the following form:

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):

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

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

⁴⁰ NER, clause 6.2.5(a).

⁴¹ NER, clause 6.12.1(11).

⁴² NER, clause 6.12.1(12).

⁴³ NER, clause 6.12.1(13).

⁴⁴ NER, clause 6.12.1(17).

⁴⁵ NER, clause 6.12.1(19).

⁴⁶ NER, clause 6.12.1(20).

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

ΔCPI_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 next regulatory control period as determined in the PTRM

TR_t is the total revenue allowable in year t

I_t is the sum of incentive scheme adjustments in year t

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

C_t is the sum of adjustments likely to incorporate but not limited to pass through events and feed-in tariff payments that are not made under jurisdictional schemes

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 – Compliance with Control Mechanisms*).
- Based on the current and proposed incentive scheme arrangements, I_t is likely to 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 next regulatory control period, which will generally result in adjustments two years after the respective performance year.
 - DMIS. Under the current DMIS,⁴⁷ the AER will calculate a total carryover amount to account for any amount of allowance unspent or not approved over the current regulatory control period 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 allowed revenue in 2016-17.

⁴⁷ AER (2008), *Demand Management Incentive Scheme, Energex, Ergon Energy and ETSA Utilities 2010-15*, October 2008, p8.

- 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 is expressed quite broadly in the formula for total revenue and is likely to be used for a number of adjustments throughout the regulatory control period. We consider that it should 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 next regulatory control period, 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 next regulatory control period is contained in our supporting document *04.01.00 – Compliance with Control Mechanisms*.

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 next regulatory control period.

The following sections set out the approaches to setting tariffs that Ergon Energy intends to adopt. Ergon Energy will submit a full Pricing Proposal to the AER following the publication of the AER's Preliminary Determination, consistent with the requirements under clause 6.18.2 of the NER.

4.3.1 Allocation of ARR to tariffs

The process for allocating and converting the ARR to network tariffs for various customers groups is described in detail in our website publication *Information Guide for Standard Control Services Pricing*.⁴⁸

At a high level, the ARR 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.

⁴⁸ Available at www.ergon.com.au/networktariffs.

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

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

In section 4.5.2 of the AER's 2010-15 Final Distribution Determination, the AER provided further guidance on the application of side constraints, and outlined a formula that Ergon Energy was to use to demonstrate that proposed DUOS prices set through the annual Pricing Proposal process met the permissible percentage.

The AER's Framework and Approach Paper did not cover matters of detail relating to annual Pricing Proposals (such as the side constraint formula). However, Ergon Energy expects the new NER requirements for the allowed rate of return, as well as changes the AER has made to the revenue cap formula will have a consequential impact on the side constraint formula.

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

4.3.3 DUOS unders and overs account

Ergon Energy currently reports to the AER annually in our Pricing Proposal on the recovery of DUOS from our network tariffs, and makes adjustments to subsequent pricing periods to account for over or under recovery of those charges in accordance with the DUOS unders and overs account set out in the Distribution Determination 2010-15.

Ergon Energy proposes to apply a principles-based approach in the next regulatory control period which seeks to balance the need to:

- reduce the amount of over or under recoveries over time
- minimise volatility for prices in the short or longer term so as not to exacerbate future over or under recoveries.

Included in our proposal is an approach that allows for flexibility if future over or under recoveries can be reasonably foreseen. Finally, we propose that the AER should allow clearance of under or

over balances to span regulatory control periods (where appropriate). Further information can be found in our supporting document *04.01.00 – Compliance with Control Mechanisms*.

4.3.4 Assignment of customers to tariff classes

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*⁴⁹ 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 processes have been effective during the current regulatory control period and are consistent with the principles governing assignment or re-assignment of customers to tariff classes set out in clause 6.18.4 of the NER. Therefore, we propose to continue to apply these procedures in the next regulatory control period.

4.3.5 Designated pricing proposal charges

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.

⁴⁹ Available at www.ergon.com.au/networktariffs.

Our supporting document⁵⁰ includes details of our reporting and calculation of designated pricing proposal charges. Ergon Energy currently reports to the AER annually in our Pricing Proposal on the recovery of TUOS from our network tariffs, and makes adjustments to subsequent pricing periods to account for over or under recovery of those charges in accordance with the Distribution Determination 2010-15. Ergon Energy proposes to continue this process in the upcoming regulatory control period.

With the exception of changes to transitional arrangements, our approach is consistent with current period arrangements.

Ergon Energy notes that a transitional definition of designated pricing proposal charges applied to Ergon Energy in the regulatory control period 2010-15.⁵¹ 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.⁵²

Consistent with the AER's position in the Framework and Approach Paper, Ergon Energy has included the charges levied on Ergon Energy for the use of the 220kV network that supplies the Cloncurry township in the operating expenditure forecasts for Standard Control Services. We have included these costs as a bottom up adjustment to the base year operating expenditure (see Appendix A for more detail).

We have also included the charges levied by Powerlink for entry and exit services at the three non-prescribed connection points in the operating expenditure forecasts for Standard Control Services for 2015-16 and 2016-17. Ergon Energy understands that Powerlink is considering applying to the AER to have these connection services classified as prescribed services for its next regulatory control period, commencing on 1 July 2017. Subject to approval by the AER, the costs will therefore be reflected in the TUOS charges from 2017-18 onwards.

4.3.6 Jurisdictional schemes

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 Scheme⁵³ will apply as a jurisdictional scheme in the next regulatory control period.

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.⁵⁴

⁵⁰ 04.01.01 – Designated Pricing Proposal Charges

⁵¹ NER, clause 11.39.6.

⁵² There will only be three non-prescribed connection points in the next regulatory control period.

⁵³ Pursuant to section 44A of the *Electricity Act 1994 (Qld)*.

⁵⁴ NER, clause 6.18.7A(b).

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
- 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 current regulatory control period, 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 next regulatory control period, Ergon Energy proposes that these costs be recovered as jurisdictional scheme amounts.

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

\$m (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20
Forecast feed-in tariff payments	110.4	106.8	104.9	102.1	99.2
Proposed recovery of jurisdictional scheme amounts	0.0	0.0	128.8	124.6	122.4

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 – Jurisdictional schemes*.

Delaying the recovery of the jurisdictional scheme amounts for the Solar Bonus Scheme means that the actual amounts paid will be known when the amount is included in the annual revenue

submitted in the Pricing Proposal. This means that there will be no need for the jurisdictional scheme amounts to be estimated in advance, and no need for an adjustment mechanism to account for differences between forecast and actual payments.

4.4 Proposed pass through events

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 next regulatory control period:

- natural disaster event
- insurance cap event
- insurance event
- retail separation event
- isolated networks separation 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 – Nominated cost pass through events*.

4.5 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 identified the following project for consideration as a contingent project:

- Cairns Northern Beach Supply Reinforcement

Our supporting document *07.09.16 – Proposed Contingent Projects* sets out the assessment approach undertaken by Ergon Energy to reach this conclusion.

We have also put forward, for consideration, a general contingent project to cover large customer connections that are unknown to Ergon Energy at this time, which will result in a material amount of shared network augmentation during the next regulatory control period.

4.6 Indicative prices

The following tables set out indicative prices for selected Standard Asset Customer (SAC)⁵⁵ tariffs for each year of the next regulatory control period, as required under clause 6.8.2(c)(4) of the NER. These indicative prices are expressed in nominal terms.

Our response to the Regulatory Information Notice provides indicative prices for our larger customers.⁵⁶

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	1.52	1.45	1.34	1.33	1.32
Energy Block 1 (\$/kWh)	0.00	0.00	0.00	0.00	0.00	0.00
Energy Block 2 (\$/kWh)	0.1531	0.1420	0.1358	0.1255	0.1241	0.1234
Energy Block 3 (\$/kWh)	0.1631	0.1799	0.1720	0.1590	0.1573	0.1563

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

TOU Residential (ERTO)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed (\$/day)	1.52	1.52	1.45	1.34	1.33	1.32
Energy Peak (\$/kWh)	0.5519	0.5519	0.5277	0.4879	0.4825	0.4795
Energy Shoulder (\$/kWh)	0.2666	0.2666	0.2549	0.2357	0.2331	0.2317
Energy Off Peak (\$/kWh)	0.0957	0.0890	0.0851	0.0787	0.0778	0.0774

⁵⁵ 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 Standard Asset Customers 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>.

⁵⁶ Refer to templates 7.6 and 7.7.

Table 17: 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	1.52	1.45	1.34	1.33	1.32
Energy Block 1 (\$/kWh)	0.00	0.00	0.00	0.00	0.00	0.00
Energy Block 2 (\$/kWh)	0.1538	0.1530	0.1463	0.1352	0.1338	0.1329
Energy Block 3 (\$/kWh)	0.1638	0.1841	0.1761	0.1628	0.1610	0.1600

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

TOU Business (EBTOU)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed (\$/day)	1.52	1.52	1.45	1.34	1.33	1.32
Energy Peak (\$/kWh)	0.4140	0.4140	0.3958	0.3659	0.3619	0.3596
Energy Shoulder (\$/kWh)	0.3066	0.3066	0.2932	0.2710	0.2681	0.2664
Energy Off Peak (\$/kWh)	0.1236	0.1327	0.1268	0.1173	0.1160	0.1153

Table 19: Indicative prices for SAC Large – Demand High Voltage – East, 2014-20

Demand High Voltage (EDHT)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed (\$/day)	341.82	328.39	328.04	304.45	303.26	302.02
Demand kW (\$/kW/month)	20.97	18.00	0.00	0.00	0.00	0.00
Demand kVA (\$/kVA/month)	0.00	0.00	15.30	14.20	14.15	14.09
Energy (\$/kWh)	0.0055	0.0060	0.0060	0.0056	0.0055	0.0055
Excess kVAr (\$/kVAr/month)	0.00	0.00	0.00	4.00	4.00	4.00

Table 20: 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	376.52	376.11	349.07	347.71	346.29
Demand kW (\$/kW/month)	28.78	25.50	0.00	0.00	0.00	0.00
Demand kVA (\$/kVA/month)	0.00	0.00	21.68	20.12	20.04	19.96
Energy (\$/kWh)	0.0055	0.0060	0.0060	0.0056	0.0055	0.0055
Excess kVAr (\$/kVAr/month)	0.00	0.00	0.00	4.00	4.00	4.00

Table 21: 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	125.67	125.53	116.51	116.05	115.58
Demand kW (\$/kW/month)	30.08	27.80	0.00	0.00	0.00	0.00
Demand kVA (\$/kVA/month)	0.00	0.00	23.63	21.93	21.85	21.76
Energy (\$/kWh)	0.0055	0.0060	0.0060	0.0056	0.0055	0.0055
Excess kVAr (\$/kVAr/month)	0.00	0.00	0.00	4.00	4.00	4.00

Table 22: 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	38.73	38.69	35.91	35.77	35.62
Demand kW (\$/kW/month)	33.63	29.00	0.00	0.00	0.00	0.00
Demand kVA (\$/kVA/month)	0.00	0.00	24.65	22.88	22.79	22.70
Energy (\$/kWh)	0.0055	0.0060	0.0060	0.0056	0.0055	0.0055
Excess kVAr (\$/kVAr/month)	0.00	0.00	0.00	4.00	4.00	4.00

4.7 Supporting documentation

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

Name	Ref	File name
Demonstration of Compliance with Control Mechanisms	04.01.00	Compliance with control mechanisms
Designated pricing proposal charges	04.01.01	Designated pricing proposal charges
Jurisdictional schemes	04.01.02	Jurisdictional schemes
Nominated cost pass through events	04.01.03	Nominated pass through events
Proposed Contingent Projects	07.09.16	Contingent projects
Regulatory Information Notice	N/A	Our response to the AER's RIN is contained in a number of files attached to this proposal

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

Introduction

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).

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.

5. Alternative Control Services

5.1 Background

As noted previously, the Framework and Approach Paper 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 Framework and Approach Paper sets out the form of control that would apply 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

Through the Framework and Approach process, 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 current regulatory control period. The AER considers this approach is “more suitable than other control mechanisms for delivering cost reflective prices”.⁵⁷

5.3 Basis of the control mechanism

The AER indicated in its Framework and Approach Paper that it will confirm the basis of the control mechanism for Alternative Control Services through the distribution determination process. There are two main approaches the AER can apply:

- a limited building block approach
- a formula-based approach, which will result 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.

⁵⁷ AER (2014a), Ibid, p67.

5.4 Formula for Alternative Control Services

The AER's proposed formula to give effect to the price cap is set out below.

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

Where:

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

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

ΔCPI_t is the annual percentage change in the 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 2015-16 year, t-2 is December 2013 and t-1 is December 2014 and in the 2016-17 year, t-2 is December 2014 and t-1 is December 2015 and so on.

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

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

The AER also proposed a formula to determine the cost build-up of services that are priced on a 'quoted' basis.

$$Price = Labour + Contractor Services + Materials + Capital Allowance$$

Where:

Labour (including on costs and overheads) – consists of all labour costs directly incurred in the provision of the service which may include but is not limited to labour on costs, fleet on costs and overheads. The labour cost for each service is dependent on the skill level and experience of the employee/s, time of day/week in which the service is undertaken, travel time, number of hours, number of site visits and crew size required to perform the service.

Contractor services (including overheads) – reflects all costs associated with the use of external labour in the provision of the service, including overheads and any direct costs incurred as part of performing the service. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred as part of performing the service, for example permits for road closures or footpath access, are passed on to the customer.

Materials (including overheads) – reflects the cost of materials directly incurred in the provision of the service, material storage and logistics on costs and overheads.

Capital allowance – represents a return on and return of capital for non-system assets (for example vehicles,⁵⁸ IT and tools) used in the provision of the service.

Ergon Energy also proposes to use this formula to establish initial prices (or base prices) for fixed fee services in the first year of the next regulatory control period.

⁵⁸ Ergon Energy has included depreciation in the fleet on-cost, which forms part of the labour cost component.

Ergon Energy has assumed the price caps will operate in the following way for our fixed fee services, Public Lighting Services and Default Metering Services:

- the initial price (or base price) will be set for each service in the first year of the regulatory control period
- from year two onwards of the regulatory control period, services will be subject to the price caps using the controls provided in the price cap formula above
- the price cap formula allows prices to be annually adjusted for:
 - inflation (CPI)
 - real cost escalation (X-factor)
 - other adjustments allowed to be passed through in capped prices (Adjustment factor).

The result of the above essentially limits the annual movement in prices to an annual adjustment or escalation. This is primarily driven by changes in CPI and other changes to underlying cost drivers for different services (X-factor).

Further details on the calculation of input prices and the application of the formula are provided in the relevant sections below and in our supporting documents *04.01.00 – Compliance with Control Mechanisms* and *05.05.01 – Inputs and Assumptions for Alternative Control Services*.

5.5 Default Metering 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 (what we call ‘Default Metering Services’). These are the meters that measure the electricity that goes into a property, and which allow electricity retailers to bill their customers. The AER has decided to separately classify this service and separately control the prices customers pay for this service.

We understand the AER’s decision to separate out Default Metering Services reflects its longer-term view of enabling metering services to be opened up to competition.

Charges to customers receiving Default Metering Services will be in the form of a daily fixed charge. The charge will be bundled with other distribution charges to the retailer as part of the usual billing process. The daily charges we are proposing for Default Metering Services in the next regulatory control period are outlined in Table 23.

Table 23: Daily metering charge, by service, 2015-20

Default Metering Services	2015-16	2016-17	2017-18	2018-19	2019-20
\$/day (nominal)					
Primary Service	0.23	0.23	0.22	0.22	0.22
Controlled load	0.09	0.08	0.08	0.08	0.08
Solar	0.06	0.06	0.06	0.05	0.05

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 activities grouped by the AER in its Framework and Approach Paper
- 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
- a 34% increase in meter installations and replacements over the next regulatory control period, driven by a significant increase in the volume of planned meter replacements
- 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.

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 – 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 the services

Default Metering Services are only a small part of activities that are covered by the metering services banner. In the AER's Framework and Approach Paper, metering services were grouped and classified in the following way:

- Types 1 to 4 metering services – these meters record detailed energy usage and have a number of other capabilities, the most significant being remote communications facilities. These meters are mostly provided for larger users in a competitive market and are therefore not regulated by the AER.
- Type 5 and 6 metering installation, provision, maintenance, reading and data services (Default 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.⁵⁹ Our service provision is regulated by Queensland-specific requirements contained in the AEMO's Metrology Procedure.⁶⁰ These requirements and obligations differ to those in other jurisdictions and our costs will reflect these differences. Default Metering Services are classified as an Alternative Control Service.
- Type 7 metering services – Type 7 services apply where the Australian Energy Market Operator (AEMO) has decided that a metering installation does not require a meter. Examples of such instances include street, traffic, park and community lighting meters. These services are classified as Standard Control Services.
- Auxiliary Metering Services – these are non-routine metering services which Ergon Energy provides on request, such as Special Meter Reads. These services are classified as Alternative Control Services and are covered in Section 5.7 of this Regulatory Proposal.

In addition to the above 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). The costs associated with this activity forms part of our Standard Control Service expenditure forecasts (refer to Appendix A and Appendix B).

Our supporting document *02.01.01 – 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.

This section of our Regulatory Proposal concentrates on prices for Default Metering Services.

5.5.4 Application of the control mechanism

Our supporting document *04.01.00 – 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.

⁵⁹ It should be noted that due to jurisdictional restrictions presently in place in Queensland, Ergon Energy does not currently provide Type 5 meters.

⁶⁰ AEMO (2012), *Metrology Procedure: Part A National Electricity Market*, July 2012.

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

Table 24: Annual Revenue Requirement for Default Metering Services, 2015-20

\$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Return on capital	4.94	6.14	6.78	6.75	5.85
Return of capital	11.05	19.88	29.78	40.68	42.55
Operating expenditure	32.80	34.39	36.92	38.98	40.60
Corporate income tax	3.11	5.56	8.22	11.04	11.12
Proposed Annual Revenue Requirement	51.90	65.96	81.69	97.45	100.13

The proposed ARR for Default Metering Services was calculated using the PTRM, which has been provided in our supporting document *05.04.07 – 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 25.

Table 25: Ergon Energy's forecast Regulatory Asset Base for Default Metering Services, 2015-20

	2015-16	2016-17	2017-18	2018-19	2019-20
Meters installed					
Meters (number)	1,279,922	1,312,782	1,345,294	1,377,737	1,409,967
Asset Base (\$m, nominal)					
Opening RAB	61.60	76.53	84.57	84.24	73.03
Capital expenditure (net of disposals and capital contributions)	25.99	27.92	29.45	29.46	30.13
Regulatory depreciation	(11.05)	(19.88)	(29.78)	(40.68)	(42.55)
Closing RAB	76.53	84.57	84.24	73.03	60.60

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:

- an annual metering service charge for the primary metering service
- a supplementary charge for *each* secondary controlled load
- a supplementary charge for solar
- a Customer Transfer (exit) fee for customers choosing another provider if competition is introduced for Type 5 and 6 metering services.

Indicative prices

Table 26 sets out the indicative prices for our Default Metering Services for each year of the next regulatory control period, as required under clause 6.8.2(c)(4) of the NER. These are expressed as simplified unit charges (\$ per unit).

Table 26: Annual indicative prices for Default Metering Services, by service, 2015-20

Default Metering Services	2015-16	2016-17	2017-18	2018-19	2019-20
\$/unit (nominal)					
Primary Service	85.31	83.56	81.87	80.23	78.66
Controlled load	31.37	30.72	30.10	29.50	28.92
Solar	21.21	20.78	20.36	19.95	19.56
Customer Transfer fee	136.97	155.78	165.71	164.00	149.13

5.6 Public Lighting Services

5.6.1 Overview

Ergon Energy manages an asset base of more than 155,000 public lights⁶¹ 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 next regulatory control period are outlined in Table 27.

⁶¹ 'Street light' and 'public light' are used interchangeably in this Regulatory Proposal.

Table 27: Daily public lighting charge, 2015-20

Public Lighting Services \$/light (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
EO&O - Major	1.1355	1.1715	1.2086	1.2469	1.2864
EO&O - Minor	0.6768	0.6982	0.7203	0.7431	0.7666
G&EO - Major	0.4604	0.4750	0.4900	0.5055	0.5215
G&EO - Minor	0.3017	0.3113	0.3212	0.3314	0.3419

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
- 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 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 – 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.

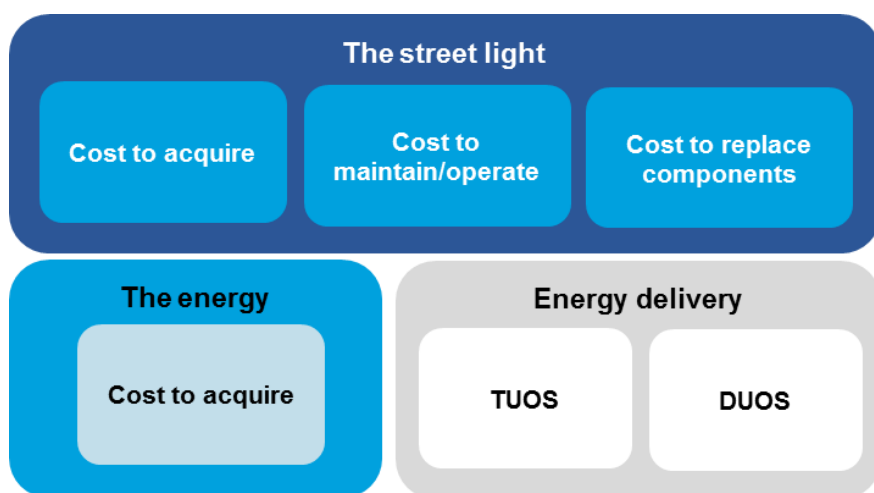
5.6.3 Nature of the services

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 6.

Figure 6: 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. Until 1 July 2014 all public lighting Alternative Control Service charges⁶² have been borne by the Queensland Government as part of the Community Service Obligation. From that date, 10% of the current Alternative Control Service charge is being 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 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

⁶² With the exception of removal/relocation of Ergon Energy owned 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.

5.6.4 Application of the control mechanism

Our supporting document *04.01.00 – 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 28 sets out the proposed ARR for Public Lighting Services for the next regulatory control period 2015-20.

Table 28: Annual Revenue Requirement for Public Lighting Services, 2015-20

\$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Return on capital	6.27	6.29	6.27	6.20	6.12
Return of capital	10.29	11.11	11.99	12.92	13.91
Operating expenditure	10.47	10.94	11.71	12.33	12.85
Corporate income tax	5.84	5.85	5.97	6.00	5.96
Proposed Annual Revenue Requirement	32.88	34.19	35.94	37.46	38.84

The proposed ARR for Public Lighting Services was calculated using the PTRM, which has been provided in our supporting document *05.02.03 – 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 29.

Table 29: Assumptions supporting the revenue calculations for Public Lighting Services, 2015-20

	2015-16	2016-17	2017-18	2018-19	2019-20
Connections					
<i>Public Lighting (number)</i>					
Ergon Energy owned & operated	89,878	90,560	91,242	91,925	92,607
Gifted & Ergon Energy operated	54,237	55,887	57,537	59,187	60,837
Growth (% per annum)	1.6%	1.6%	1.6%	1.6%	1.5%
Asset Base (\$m, nominal)					
Opening RAB	78.25	78.41	78.20	77.36	76.39
Capital expenditure (net of disposals and capital contributions)	10.45	10.90	11.15	11.95	13.02
Regulatory depreciation	(10.29)	(11.11)	(11.99)	(12.92)	(13.91)
Closing RAB	78.41	78.20	77.36	76.39	75.50

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 current regulatory control period, 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 current regulatory control period 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 next regulatory control period, 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, for the whole regulatory control period, are set out in Table 30.

Table 30: Exit fees, 2015-20 (\$ nominal)

Public lighting category	Exit fee (per light)
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 Other Alternative Control Services

5.7.1 Nature of the services

Table 31 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.⁶³

Table 31: Other Alternative Control 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
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
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

⁶³ For further information on the individual services refer to 02.01.01 – Classification Proposal.

Service grouping	Services	Service description
		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. 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.

The first step in determining prices is to identify which services will be priced on a quoted basis versus a fixed fee basis. Table 32 provides a summary of our proposed pricing approach for each service grouping.

Table 32: Proposed approach to pricing of other Alternative Control Services, 2015-20

Service grouping	Services	Pricing approach
Pre-connection Services	Connection application services	Fixed / 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	Fixed
Post Connection Services	Connection management services (post connection)	Fixed / Quoted
	Accreditation of alternative service providers and approval of their designs, works and materials	Fixed / Quoted
Metering Services	Auxiliary Metering Services	Quoted
Ancillary Network Services	Services provided in relation to a ROLR event	Quoted
	Other recoverable works	Fixed / Quoted

Once this distinction is made, the prices for each service will be calculated in accordance with the AER's proposed formulas (see Section 5.4). Actual prices for services subject to a fixed fee and example prices for quoted price services will be provided in our annual Pricing Proposal.

5.7.3 Fixed fee 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 current regulatory control period in determining prices for fixed fee services. We will charge for:

- the cost of labour by applying labour rates previously approved by the AER in 2014-15 (escalated annually). 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
- the capital costs associated with fleet⁶⁴ and other non-system assets, by calculating an amount in accordance with the value of these assets used in the provision of fixed fee and quoted price services
- the Goods and Services Tax (GST) in accordance with relevant legislation.

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

Table 33 sets out the indicative prices for our fixed fee services for each year of the next regulatory control period, as required by clause 6.8.2(c)(4) of the NER.

Table 33: Indicative prices for fixed fee 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	936.78	984.50	1060.81	1124.80	1176.38
Application fee - Basic or standard connection - Micro-embedded generators	52.86	55.54	59.85	63.46	66.37
Application fee - Basic or standard connection - Micro-embedded generators - Technical assessment required	231.51	243.30	262.14	278.00	290.74
Application fee - Real estate development connection	980.15	1030.09	1109.93	1176.89	1230.85
Protection and Power Quality assessment prior to connection	1429.21	1502.05	1618.33	1716.36	1794.96
Temporary connection, not in permanent position - single phase metered - urban/short rural feeders	607.18	637.66	686.58	727.62	760.37
Temporary connection, not in permanent position - single phase metered - long rural/isolated feeders	971.49	1020.26	1098.53	1164.20	1216.60
Temporary connection, not in permanent position - multi phase metered - urban/short rural feeders	607.18	637.66	686.58	727.62	760.37

⁶⁴ Excluding depreciation, which is included in the fleet on-cost.

Pricing category \$/unit (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Temporary connection, not in permanent position - multi phase metered - long rural/isolated feeders	971.49	1020.26	1098.53	1164.20	1216.60
Supply abolishment during business hours - urban/short rural feeders	364.31	382.60	411.95	436.57	456.22
Supply abolishment during business hours - long rural/isolated feeders	728.62	765.20	823.90	873.15	912.45
De-energisation during business hours - urban/short rural feeders	101.76	106.78	114.89	121.66	127.05
De-energisation during business hours - long rural/isolated feeders	607.18	637.66	686.58	727.62	760.37
Re-energisation during business hours - urban/short rural feeders	80.91	84.91	91.36	96.74	101.02
Re-energisation during business hours - long rural/isolated feeders	565.89	594.30	639.90	678.15	708.67
Re-energisation during business hours - after de-energisation for debt - urban/short rural feeders	80.91	84.91	91.36	96.74	101.02
Re-energisation during business hours - after de-energisation for debt - long rural/isolated feeders	565.89	594.30	639.90	678.15	708.67
Accreditation of alternative service providers - real estate developments	937.92	985.72	1062.03	1126.36	1177.94
Prevented access - one person crew - urban/short rural feeders	56.75	59.55	64.06	67.83	70.82
Prevented access - one person crew - long rural/isolated feeders	227.01	238.19	256.23	271.32	283.29
Prevented access - two person crew - urban/short rural feeders	116.89	122.75	132.17	140.06	146.36
Prevented access - two person crew - long rural/isolated feeders	467.56	491.02	528.67	560.25	585.45

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 price services

Quoted price services encompass those services Ergon Energy undertakes at the request of 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 current regulatory control period in determining prices for quoted price services. We will charge for:

- the cost of labour by applying labour rates approved by the AER in 2014-15 (escalated annually). 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 price 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 fleet⁶⁵ and other non-system assets, by calculating an amount in accordance with the value of these assets used in the provision of fixed fee and quoted price services. For the design and construction of connection assets for major customers, Ergon Energy is proposing to apply 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 price services is provided in our supporting document *05.05.01 – Inputs and assumptions for Alternative Control Services*.

Given the nature of quoted price 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 price services. This worked example, including indicative prices for other quoted price services, are provided in our supporting document *05.05.01 – 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 to continue our current procedures for assigning or reassigning customers to tariff classes, as set out in our *Information Guide for Alternative Control Services Pricing*.⁶⁶

⁶⁵ Excluding depreciation, which is included in the fleet on-cost.

⁶⁶ Available at www.ergon.com.au/networktariffs.

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 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 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 on these procedures are set out in our *Information Guide for Alternative Control Services Pricing*.

5.9 Supporting documentation

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

Name	Ref	File name
Classification Proposal	02.01.01	Classification Proposal
Compliance with Control Mechanisms	04.01.00	Compliance with Control Mechanisms
Public Lighting Services Summary	05.01.01	Public Lighting Summary
Public Lighting Services PTRM	05.02.03	PLPTRM Data Model with Prices
Default Metering Services Summary	05.03.01	Default Metering Services Summary
Default Metering Services PTRM	05.04.07	MTPTRM Data Model
Inputs and assumptions for Alternative Control Services	05.05.01	Inputs and assumptions for ACS

Appendix A: Operating expenditure forecasts for Standard Control Services

Introduction

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 proposal brings our operating costs for the 2015-20 regulatory control period down to \$1.8 billion, from \$1.9 billion in the previous period. Network Maintenance is our largest cost – at \$1.3 billion over the five year period.

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 was devastated by a major cyclone.

Appendix A: Operating expenditure forecast for Standard Control Services

1 Overview

Our proposed operating expenditure has reduced by approximately 6% from our actual and estimated spend in the current regulatory control period. It incorporates efficiencies in vegetation management, line inspection and pole defect management. At the same time, we are incorporating increasing expenditure in non-network alternatives to address network demand, rather than employing costly capital solutions. We are also proposing to include a new form of insurance cover given our unique exposure to extreme wind-generated events like Cyclone Yasi.

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

Table 34: Forecast operating expenditure, 2015-20

\$'000 (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Operating expenditure	349,600	356,070	363,610	372,890	378,960	1,821,130

This appendix outlines:

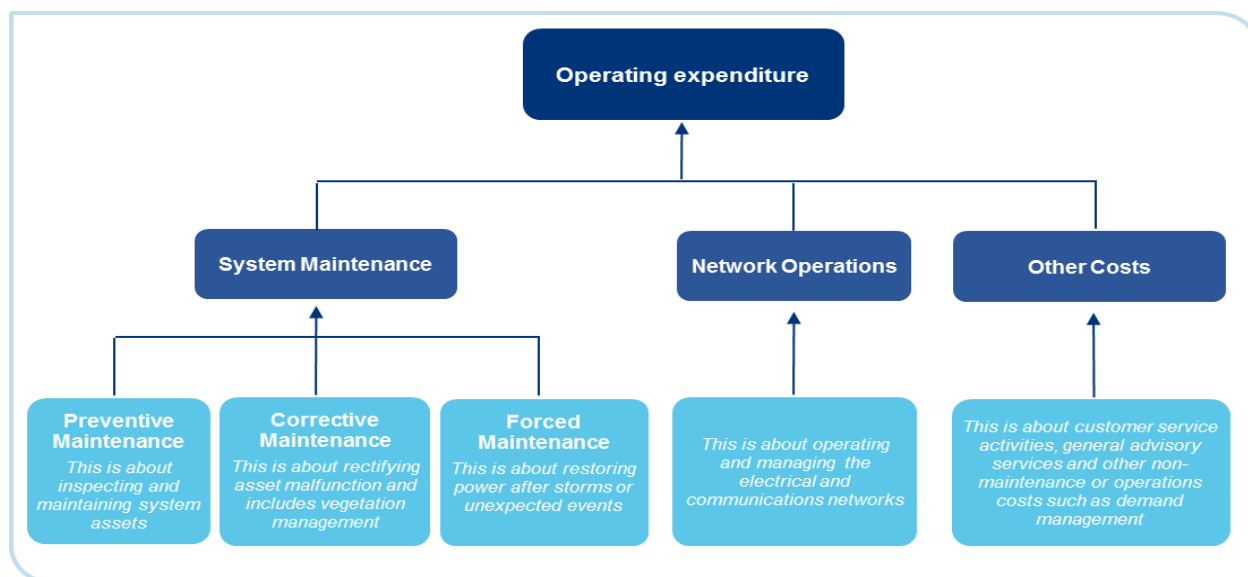
- why Ergon Energy incurs this level of operating expenditure, and the various categories of expenditure that make up Ergon Energy's operating program
- our level of operating expenditure in the current regulatory control period and how it compares to the efficient level of operating expenditure set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

2 Components of our operating expenditure requirement

2.1 Direct operating expenditure

The components of our direct operating expenditure program are illustrated in Figure 7.

Figure 7: Components of our operating expenditure requirement



Ergon Energy's direct operating expenditure requirements⁶⁷ 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.

The routine maintenance programs are supported by maintenance strategies, management plans and Defect Classification Manuals specific to each asset category. Non-routine maintenance involves timely response to instances of non-compliance against acceptance criteria identified during the routine maintenance process. Such activity may include more intensive (frequent) inspection cycles as the most cost effective manner in extending asset life cognisant with safety and regulatory obligations.

Ergon Energy is also required to ensure that sufficient funding and resources are available to respond to unexpected or unplanned events and to safely and efficiently restore supply and asset integrity.

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.

⁶⁷ Section 3 of our supporting document 06.01.02 – System related operating expenditure summary.

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 current regulatory control period, 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 next regulatory control period 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 alternatives solutions, as a tactical response to network problems – primarily where growing customer peak demand requirements create the need to expand network capacity.

Table 35 provides Ergon Energy's forecast operating expenditure for each year of the next regulatory control period, disaggregated by program of expenditure.

Table 35: Proposed operating expenditure by category, 2015-20

\$'000 (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Network Operating Costs						
Network Operating Costs	34,260	34,990	36,590	37,650	38,330	181,820
Network Maintenance Costs						
Preventive Maintenance	77,520	79,240	82,950	85,460	87,090	412,260
Corrective Maintenance	108,280	110,660	115,810	119,280	121,520	575,550
Forced Maintenance	64,750	65,990	68,860	70,720	71,850	342,170
<i>Subtotal</i>	<i>250,550</i>	<i>255,890</i>	<i>267,620</i>	<i>275,460</i>	<i>280,460</i>	<i>1,329,980</i>
Other Costs						
Customer Services	4,370	4,490	4,720	4,880	4,980	23,440
Other Operating Costs	60,420	60,700	54,680	54,900	55,190	285,890
<i>Subtotal</i>	<i>64,790</i>	<i>65,190</i>	<i>59,400</i>	<i>59,780</i>	<i>60,170</i>	<i>309,330</i>
Total forecast operating expenditure	349,600	356,070	363,610	372,890	378,960	1,821,130

Further information on the forecast expenditure for each category is provided in the supporting document *06.01.02 – System Related Operating Expenditure Summary (System Opex 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 – Operating Expenditure Forecast Summary (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 and current period performance

Table 36 and Table 37 provide Ergon Energy's actual operating expenditure for each year of the previous and current regulatory control periods, disaggregated by program of expenditure.⁶⁸

For comparison purposes, we have categorised this information in the same way as our operating expenditure forecast set out in Table 35. Information provided for both regulatory control periods are based on the CAM applying in the current regulatory control period.

Expenditure associated with FiT payments has been excluded from the prior and current period performance. These costs do not form part of our Direct Control Services from 1 July 2015.

Table 36: Prior period operating expenditure by category, 2005-10

\$'000 (real 2014-15)	2005-06	2006-07	2007-08	2008-09	2009-10	Total
Network Operating Costs						
Network Operating Costs	20,067	30,804	36,157	35,709	33,154	155,891
Network Maintenance Costs						
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>
Other Costs						
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>
Total actual operating expenditure	323,657	327,080	350,616	352,081	345,006	1,698,440

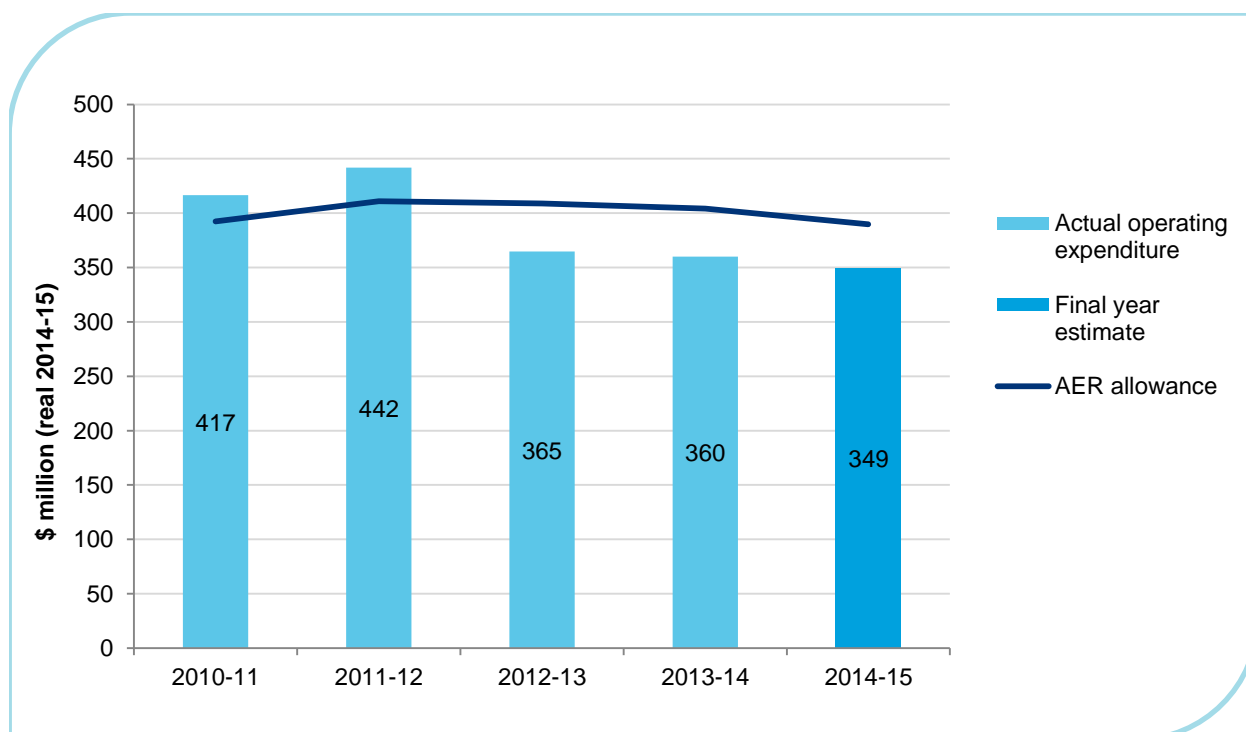
⁶⁸ NER, clause S6.1.2(7).

Table 37: Current period operating expenditure by category, 2010-15

\$'000 (real 2014-15)	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Network Operating Costs						
Network Operating Costs	36,168	35,075	34,775	35,241	34,462	175,722
Network Maintenance Costs						
Preventive Maintenance	83,105	103,534	92,096	73,440	78,602	430,777
Corrective Maintenance	117,323	147,271	113,905	107,694	106,502	592,694
Forced Maintenance	105,368	67,059	73,115	69,413	63,850	378,805
<i>Subtotal</i>	<i>305,795</i>	<i>317,864</i>	<i>279,116</i>	<i>250,547</i>	<i>248,954</i>	<i>1,402,276</i>
Other Costs						
Meter Reading	12,985	14,282	13,330	13,195	14,070	67,862
Customer Services	20,980	27,338	32,389	26,125	16,089	122,922
Other Operating Costs	40,654	47,193	5,073	35,056	35,862	163,838
<i>Subtotal</i>	<i>74,619</i>	<i>88,813</i>	<i>50,793</i>	<i>74,377</i>	<i>66,021</i>	<i>354,622</i>
Total actual operating expenditure	416,582	441,752	364,683	360,165	349,437	1,932,620

As illustrated in Figure 8, Ergon Energy expects to deliver an operating program less than the AER approved allowance over the current regulatory control period.

Figure 8: Actual vs. allowed operating expenditure, 2010-15



The following sections summarise the factors that shaped our operating expenditure in the current regulatory control period. These factors will play a role in our need for ongoing operating expenditure to the level forecast.

3.3 Key drivers of expenditure and outcomes in the current 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.

Our *System Opex Summary* document outlines the impact that Cyclone Yasi had on Ergon Energy's customers and network infrastructure, and the consequential impact on other programs of work. This combined with other major weather events (flooding and impacts from ex-cyclone Oswald) 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 8 above).

Our *System Opex Summary* document 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)*,⁶⁹ 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

⁶⁹ OA.01.02 – Ergon Energy's Journey to the Best Possible Price.

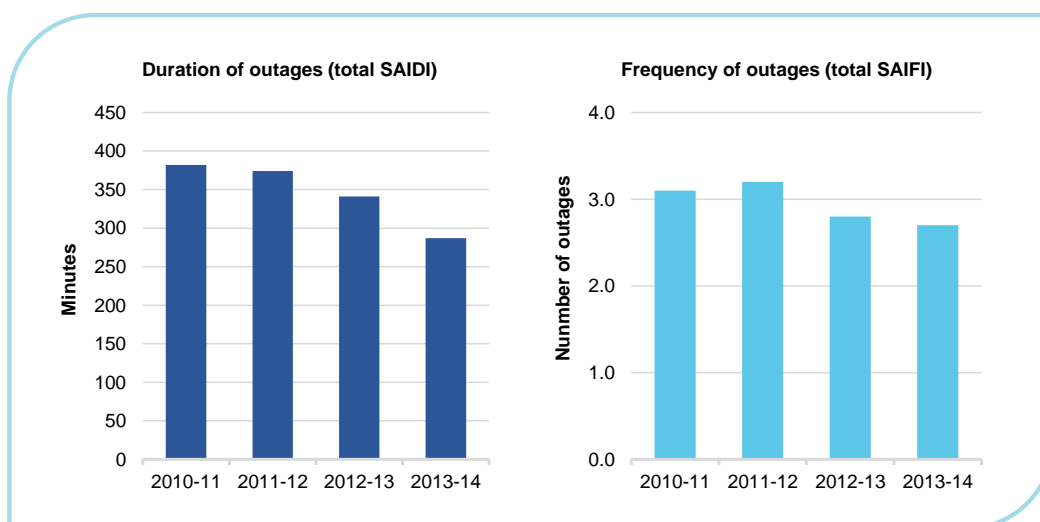
- reducing total expenditure spend by over 20% against the regulatory allowance
- contracting business headcount by 17.5% since April 2012
- success in securing new security and reliability standards that will ease investment.

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 current regulatory control period 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 9: SAIDI and SAIFI, 2010-11 to 2013-14



Our consumer engagement research is showing our customers are now generally satisfied with the level of supply they receive.⁷⁰ 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.

⁷⁰ Refer to our supporting document *0A.01.04 – Informing our plans, Our Engagement Program*.

4 Factors influencing forecasts in 2015-20

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

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 next regulatory control period.

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 will continue until the end of the current regulatory control period. The changes will provide Ergon Energy with a further opportunity to review the way we will meet consumers' 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 consumer expectations to identify where further efficiencies can be achieved.

Our *Best Possible Price* document outlines how Ergon Energy made significant adjustments to our forecast operating expenditure requirement to deliver lower price outcomes for customers. As discussed in detail in the forecast methodology in Section 5, these adjustments take the form of an upfront one-off adjustment to our base year overhead costs (therefore impacting capital and operating expenditure) and an ongoing productivity adjustment.

Bringing forward future benefits for customers

Ergon Energy's actual operational overhead costs for 2013-14 and 2014-15 are likely to be at a higher level than the top down reduction in our forecast implies. This is because our commitment to future cost reductions are not certain, and even if realised, will only start to be delivered over the term of the regulatory control period 2015-20.

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 consumers, 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 consumers in terms of making sustainable price reductions and strikes an appropriate balance with the incentives Ergon Energy will experience under the EBSS. Feedback from consumers and other key stakeholders (including the Consumer Challenge Panel) also indicates there is support for energy companies to deliver the best possible price to consumers as soon as possible, and not unduly defer or delay the sharing of benefits.⁷¹

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 consumers, we are cognisant of our consumers' 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 next regulatory control period 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.

5 Forecast methodology

In the previous sections we identified the forecast operating expenditure requirements for the next regulatory control period 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,⁷² 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 2013,⁷³ setting out our approach for forecasting expenditure for the next regulatory control period, including our approach to operating expenditure. This section should therefore be read in conjunction with these documents.

⁷¹ OA.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%202%20%28Hugh%20Grant%29%20-%20Presentation%20to%20Qld%20consumer%20forum%20-%208%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.

⁷² 06.01.01

⁷³ Refer to <https://www.ergon.com.au/network/network-management/future-investment/future-direction>.

5.1 Key assumptions

Table 38 outlines the key assumptions underpinning our operating expenditure forecasts for the next regulatory control period, consistent with NER requirements.⁷⁴

Table 38: 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. The potential for future changes arising from recent announcements regarding the Queensland Government's Strong Choices Plan that could see the assets of distribution networks being subject to a leasing arrangement have not been factored into our expenditure assumptions for the regulatory control period 2015-20.
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 2012-13 audited financial statements are an appropriate starting point for the establishment of an efficient base year.	The 2012-13 financial year represented the most recent audited financial statements available for the purpose of forecasting the regulatory control period 2015-20 to meet the timetable for submission to the AER on 31 October 2014 and the most logical representative base year. While the audit of 2013-14 financial accounts has been completed, the results of that financial audit were not available until the end of August 2014 to allow sufficient analysis to occur for submission of this Regulatory Proposal.
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.

⁷⁴ 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*.

Assumption	Application
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. ⁷⁵ 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.
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 current regulatory control period. We have attempted to reconcile our approach with the AER's Expenditure Forecast Assessment Guideline, but have found that some departures have been necessary.

The NER requires that any forecast be developed on a basis consistent with Ergon Energy's approved CAM.⁷⁶ In order to be consistent with the Guideline and compliant with the NER, it has been necessary for Ergon Energy to apply a BST approach to most of our regulated direct and overhead expenditure that is not direct capital expenditure. As part of its Better Regulation work program, the AER released its Expenditure Forecast Assessment Guideline⁷⁷ and Explanatory Statement,⁷⁸ setting out the AER's intended approach to assessing expenditure forecasts. The Explanatory Statement appears to

"...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

⁷⁵ 06.02.02 – Jacobs: Cost Escalation Factors 2015-20

⁷⁶ NER, clause 6.5.7(b)(2)

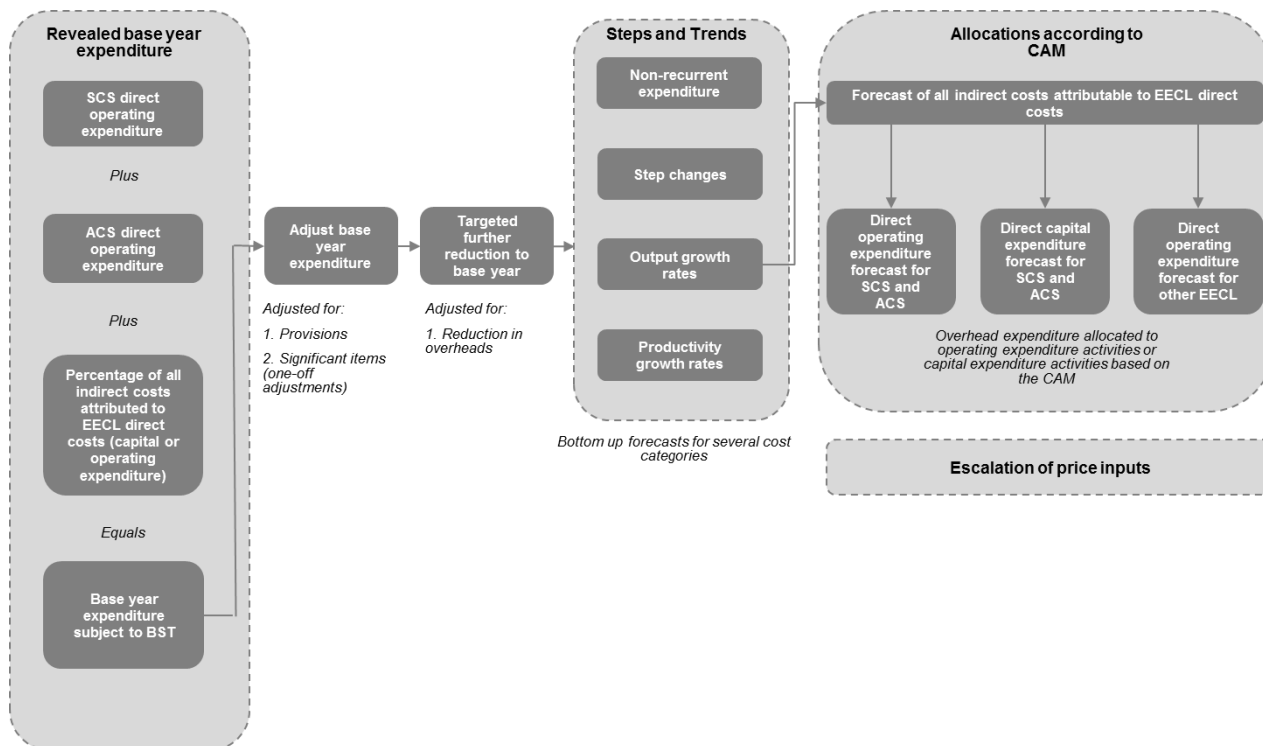
⁷⁷ Refer to <http://www.aer.gov.au/node/18864#>.

⁷⁸ Refer to <http://www.aer.gov.au/sites/default/files/Expenditure%20Forecast%20Assessment%20Guideline%20-%20Explanatory%20Statement%20-%20FINAL.pdf>.

indicate a preference by the AER for the application of a BST approach to the forecasting of operating expenditure requirements.

As a result, we have revised our operating expenditure forecasting approach for the next regulatory control period. Figure 10 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 10: BST methodology



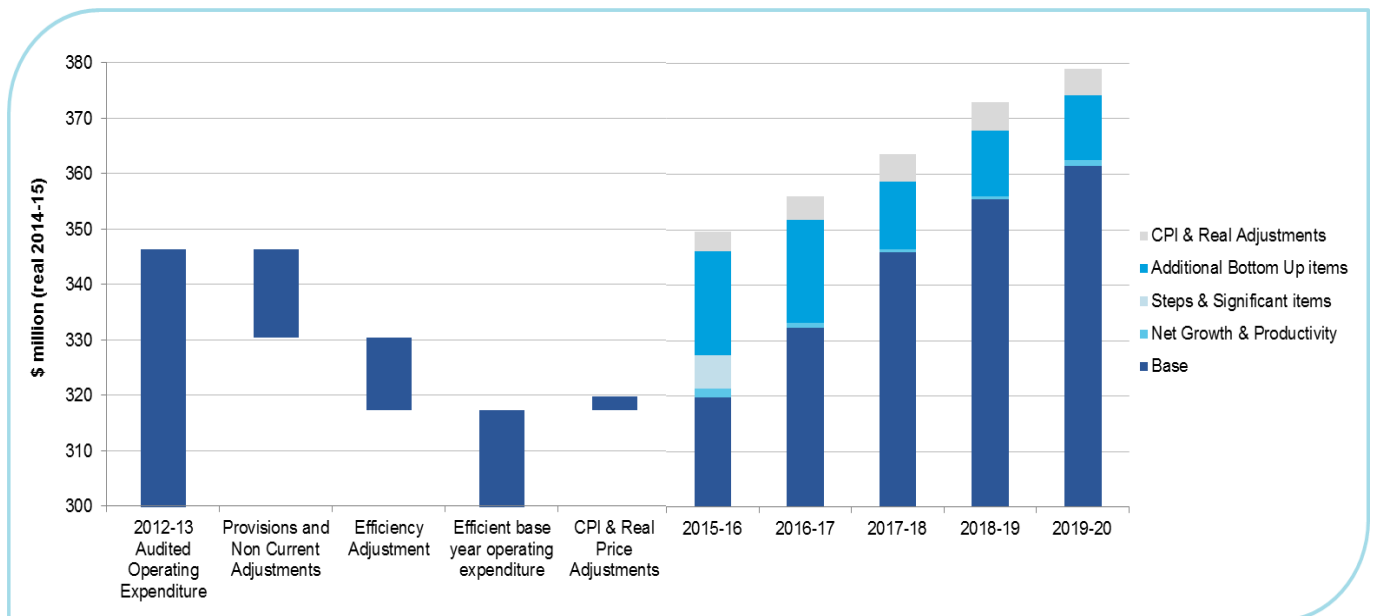
5.3 Base step trend forecasting approach

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

- selecting a base year
- identifying the direct and indirect costs that need to be applied to BST
- making appropriate adjustments for movements in provisions
- making one-off adjustments to the base year
- making further targeted reductions to the base year
- identifying and applying any step changes
- applying a rate of change consisting of output growth, real price growth and productivity growth to establish the trend.

The BST outcomes for Ergon Energy's Standard Control Services are depicted in the Figure 11 below.⁷⁹

Figure 11: BST outcomes for Ergon Energy



Base year assumption 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 2012-13 financial accounts as the base year for the purposes of forecasting operating expenditure for the Regulatory Proposal. 2012-13 was the third year of Ergon Energy's current regulatory control period and represents the most recent financial year for which audited regulatory accounts were available at the time the operating expenditure forecasts were prepared.

Establishing Functional Areas for forecasting purposes

Ergon Energy has mapped our revealed costs from our audited 2012-13 financial data to groupings called 'Functional Areas' for the purposes of our base year data. 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.

Some Functional Areas are not included in the BST methodology and instead are subject to bottom up forecast (see Section 5.4).

⁷⁹ This represents the adjusted forecast following allocation of overheads in accordance with the CAM.

Adjustments to the base year for forecasting purposes

Adjustments to the 2012-13 audited operating expenditure numbers have been made to remove expenditure incurred in the base year that related to specific one-off or unusual events. In our *Opex Forecast Summary* document we detail the types of changes made. Examples include:

- movements in provisions consistent with the AER Guideline
- one-off adjustments to the base year revealed costs, such as forced maintenance associated with Cyclone Oswald and efficiencies likely to be achieved through improved understanding of asset condition and degradation and vegetation management.

Targeted further reduction in overhead costs

In seeking to address the long term interests of consumers to achieve further sustainable price reductions, Ergon Energy has proposed a further top down adjustment of 15% to be applied to all overhead cost Functional Areas except Fleet, ICT, and IT Asset Charges in our 2012-13 base year operational overhead costs, coupled with a broad based 1% productivity adjustment going forward. The rationale supporting this adjustment is detailed in our supporting document, *Best Possible Price*.⁸⁰

Non-recurrent expenditure and step changes

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 (non-recurrent expenditure) or on an ongoing basis (step changes in expenditure). Examples of areas of non-recurrent expenditure and step changes in expenditure include:

- additional demand management operating expenditure requirements aimed at deferring future capital expenditure but which were not included in the base year
- changes to the regulatory treatment of current period TUOS charges which are now required to be included as operating expenditure
- increases in ICT support costs due to the introduction of new systems.

Our supporting document *06.01.04 – Step Changes for Operating Costs* provides further information on step changes.

Rate of change factors

Ergon Energy's methodology trends the base year expenditure by applying a rate of change to each Functional Area on an annual basis comprised of:

- output growth
- real price growth
- productivity growth.

The change factors that Ergon Energy has applied were developed with reference to the relevant requirements of the NER with respect to realistic expectations of demand and recent AER determinations for other NSPs.

⁸⁰ 0A.01.02 – Ergon Energy's Journey to the Best Possible Price.

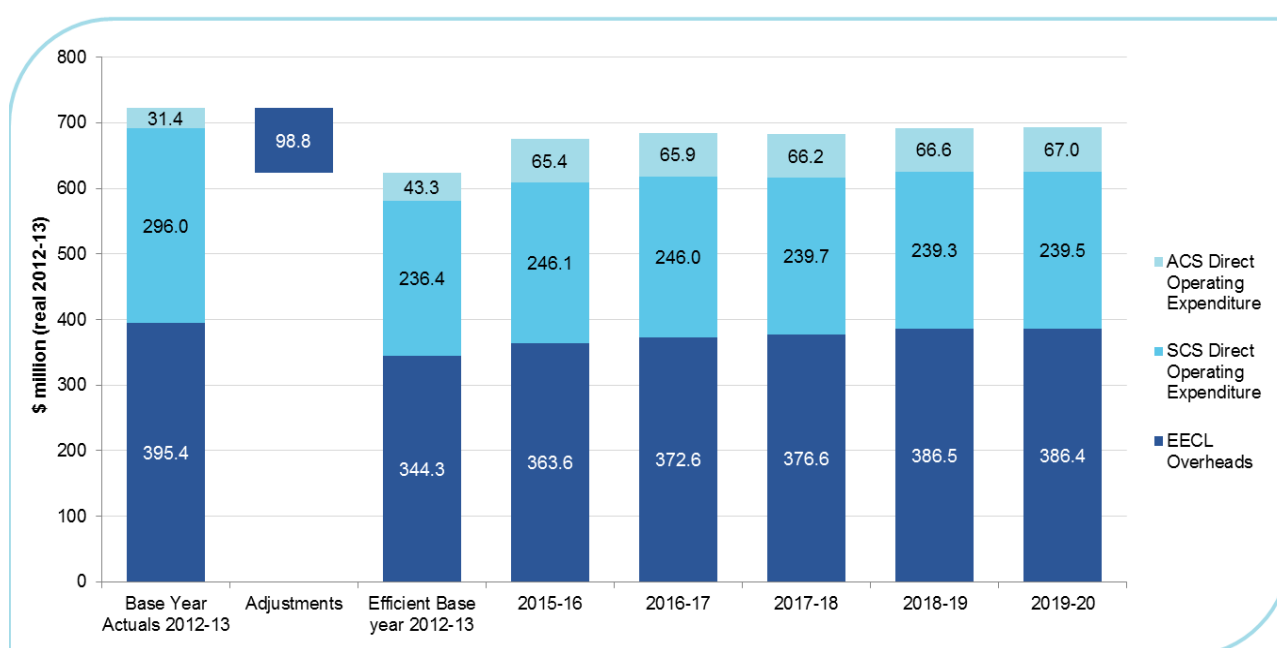
Detailed analysis supporting the basis for our rate of change factors is provided in the following documents supporting this appendix of the Regulatory Proposal:

- *Opex Forecast Summary* document – calculation of network and customer growth, and the productivity growth rate
- supporting document *06.02.02 – Jacobs: Cost Escalation Factors 2015-20*.

Allocation of forecasts according to the Cost Allocation Method

Figure 12 below shows the impact of the BST when applied to all Functional Areas, including Alternative Control Services direct operating expenditure and overhead cost pools.

Figure 12: Total forecast overhead using BST approach



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.

The process for the allocation of overhead costs to distribution services is as follows:

- 1 Allocation of overhead costs between the regulated distribution services provided by Ergon Energy and each of the unregulated services provided by the Ergon Energy Group.
- 2 For the costs allocated to the regulated distribution services provided by Ergon Energy, further allocation of the costs between regulated operating expenditure and regulated capital expenditure.
- 3 Calculation of the Shared Cost Percentage Rate for each of regulated operating expenditure and regulated capital expenditure. The Shared Cost Percentage Rate is the proportion of shared costs for a particular budgeted operating expenditure activity over the total budgeted operating expenditure.
- 4 Application of the Shared Cost Percentage Rate to direct operating expenditure and direct capital expenditure.

5.4 Use of bottom-up forecasting approach where BST is not appropriate

While the AER's Guideline appears to prefer the use of a BST methodology for operating expenditure, Ergon Energy has applied a bottom-up forecasting method for Functional Areas that are materially affected by scope changes, or are considered to be non-recurrent in nature. Ergon Energy considers that it would be inappropriate to forecast costs of this nature using a trend escalator.

The following Functional Areas were forecast using a bottom-up approach:

- Chumvale
- Powerlink
- ICT
- parametric insurance
- debt raising costs
- Demand Management Innovation Allowance.

Chumvale

"Chumvale" refers to the substation on the unregulated 220kV network which services the Cloncurry Township. Under clause 11.39 of the NER, the charges levied on Ergon Energy for the use of this line are treated as 'designated pricing proposal charges'. It is expected that the cost is passed through as TUOS charges via Ergon Energy's annual Pricing Proposal. The cost is not included in the operating expenditure building block, and is not reflected in the base year operating expenditure.

The transitional rules set out in Chapter 11 of the NER only apply for the current regulatory control period, which means that the cost will need to be included in the forecast operating expenditure used to determine the ARR for the next regulatory control period. The AER has already acknowledged that Ergon Energy may include these costs in our Regulatory Proposal for the next regulatory control period.⁸¹

This is considered to be a bottom up item as the cost was not part of the operating expenditure for the base year in the BST. Further, it is a recurrent operating cost for the next regulatory control period of which the cost is known with certainty and the annual charge is not trended.

The forecast charges for the use of the 220kV line are \$0.80 million (in \$2012-13) from 2015-16.

Powerlink

"Powerlink" refers to the cost for entry and exit services charged by Powerlink at four non-prescribed connection points – Queensland Nickel, Stoney Creek, Kings Creek and Oakey Town.⁸² Under transitional clause 11.39 of the NER, the charges levied on Ergon Energy are treated as 'designated pricing proposal charges' in the current regulatory control period. It is expected that the cost is passed through to customers as TUOS charges via Ergon Energy's annual Pricing Proposal. The cost is not included in the operating expenditure building block, and is not reflected in the base year operating expenditure.

⁸¹ AER (2014a), Ibid.

⁸² There will only be three non-prescribed connection points in the next regulatory control period.

The charges for the entry and exit services for the non-prescribed connection points are treated as adjustments to the base operating expenditure for 2015-16 and 2016-17, as these costs will be incurred as operating expenditure in those two years only. The connection points are expected to become regulated from 1 July 2017 (subject to AER approval), which means that the charges for the entry and exit services provided at those connection points will be included in the TUOS charges for the final three years of the next regulatory control period.

The forecast charges for these entry and exit services are \$11.8 million (in \$2012-13) for 2015-16 and 2016-17.

ICT operating expenditure

The scope of the ICT investments over the next regulatory control period will include all software, data, computer and communications hardware required to provide systems supporting business functions and processes in support of Ergon Energy's services.

Ergon Energy relies on a service level agreement with SPARQ for most of our ICT requirements. Ergon Energy accounts for the cost of SPARQ's service level agreement as operating expenditure. Because this will incorporate both ICT operating and investing activities, operating expenditure forecasts for the asset service fee and non capital project costs of ICT will have a different profile to other recurrent expenditure items and therefore will not adopt the common escalators.

Ergon Energy has identified that the BST forecasting method is considered not suitable for forecasting the following types of ICT operational expenditure:

- ICT Non Capital Project Costs, which consist of non-recurrent major investments that do not meet the capital definitions under relevant accounting standards
- ICT Asset Service Fees (depreciation and finance costs recovered by SPARQ through charges to Ergon Energy), which represent operational expenses resulting from non-recurrent major investments capitalised in SPARQ.

Ergon Energy has adopted a bottom-up approach to the calculation of these costs, which are represented in Table 39.

Table 39: SPARQ non capital project costs and asset service fees, real \$2012-13 million

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Non Capital Project Costs	3.56	6.27	5.81	3.65	1.50	20.79
Asset service fees	30.43	34.08	36.33	43.26	43.07	187.19

The SPARQ service charge will also be subject to the corporate overhead allocation process in accordance with the CAM.

Parametric insurance

Ergon Energy's approach in the regulatory control period 2010-15 to funding damage or loss of electricity network assets caused by typical storms and low category rated cyclones is through a combination of the operating expenditure (forced maintenance) and capital expenditure (asset replacement), allowances set by the AER. For large storms and high category rated cyclones, Ergon Energy may fund the cost by using the cost pass through provisions in the NER.

As an alternative to historic arrangements, Ergon Energy has worked with our insurance broker, to develop options for covering the cost of damage or loss of electricity network assets caused by storms and cyclones.

Ergon Energy has identified a parametric insurance product that will address applicable NER requirements and provide an efficient and prudent level of insurance 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. These costs have been incorporated within our operating expenditure forecast.

Detailed analysis supporting the cost and justifying parametric insurance as a cost in our operating expenditure forecast is provided in Section 2.10 of the *Opex Forecast Summary* document.

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 2.11 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 request,⁸³ if successful, will also impose a regulatory constraint on Ergon Energy requiring the estimate of the return on debt to be completed by 31 December each year to enable pricing proposals to be submitted to the AER earlier than is currently required. By extension, this will necessitate DNSPs also having to complete their financing transactions prior to 31 December.

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 six months ahead (i.e. six months prior to the commencement of the next regulatory year in the regulatory control period). If this occurs, the estimate for early issuance costs provided above should be recalculated based on a six 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 as a bottom-up line item in our operating expenditure forecast. To avoid double counting of the allowance, no further adjustments have been made to the revenue model.

⁸³ AEMC (2014). *Draft Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 28 August 2014.

6 Outcomes for customers

Table 40 summarises the operating expenditure forecast comprised on both the BST and bottom-up forecasts.

Table 40: Proposed operating expenditure build up under the BST (\$m)

Standard Control Service (SCS) operating expenditure forecast		2012-13	2012-13 Adjusted	2015-16	2016-17	2017-18	2018-19	2019-20
Base year operating expenditure		261.16	260.23	240.78	226.34	226.55	226.50	226.43
Change factors	Output growth			3.52	2.47	2.22	2.19	2.78
	Productivity growth			(2.41)	(2.26)	(2.27)	(2.27)	(2.26)
Step changes ¹								
Non-network alternatives				4.00				
Embedded generation				(0.50)				
Non-recurrent ¹								
Non-recurrent operating expenditure adjustments			(24.75)	(19.05)				
Total BST operating expenditure		261.16	235.48	226.34	226.55	226.50	226.43	226.94
Bottom-up adjustments ¹								
DMIA			0.88	0.93	0.90	0.88	0.86	0.84
Parametric insurance			-	12.03	11.73	11.44	11.15	10.87
Powerlink			-	5.88	5.92	-	-	-
Chumvale			-	0.83	0.82	0.81	0.80	0.79
Operating expenditure before escalation		261.16	236.36	246.02	245.92	239.64	239.24	239.44
Real price growth		-	-	20.21	23.22	25.95	29.04	32.26
Overheads (\$2014-15)		85.11	80.82	83.37	86.91	98.02	104.62	107.25
Total SCS operating expenditure forecast (\$2014-15)		346.27	317.18	349.60	356.05	363.61	372.90	378.95
Debt raising costs		-	-	11.57	11.97	12.30	12.55	12.82
Total SCS operating expenditure forecast including debt raising costs		346.27	317.18	361.17	368.02	375.91	385.45	391.77

Note 1: Adjustments that are made to overheads are factored into the overheads line item. The full effect of adjustments to overheads throughout the document will not be visible in Standard Control Service only tables and are allocated consistent with the CAM.

7 Recognising the AER's 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.

In its information paper, the AER notes that its assessment techniques are underpinned by a nationally consistent framework for network businesses to report. The Guideline explains what data the AER needs and why. The AER notes the following assessments may be used:

- economic benchmarking – productivity measures used to assess a business' efficiency overall
- category level analysis – comparing how well a business delivers services for a range of individual activities and functions, including over time and with its peers
- predictive modelling – statistical analysis to predict future spending needs, currently used to assess the need for upgrades or replacement as demand changes (augmentation capital expenditure, or augex) and expenditure needed to replace aging assets (replacement capital expenditure, or repex)
- trend analysis – forecasting future expenditure based on historical information, particularly useful for operating expenditure where spending is largely recurrent and predictable
- cost benefit analysis – assessing whether the business has chosen spending options that reflect the best value for money
- project review – a detailed engineering examination of specific proposed projects or programs.

The AER's Guideline contains a great deal of prescription around different types of tools or techniques for assessing and/or substituting operating expenditure forecasts. However, it is not clear to us exactly how the AER will apply the Guideline to Ergon Energy and what information and models it will rely upon. This is particularly the case in the absence of the AER's annual benchmarking report.

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 report⁸⁴ notes 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.

⁸⁴ Huegin (2014), *Productivity change in the context of the AER Guideline*. Refer to 06.01.03 – Huegin Productivity Analysis.

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 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.”⁸⁵

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 – 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.

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 next regulatory control period. 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

⁸⁵ 06.01.03 – *Huegin Productivity Analysis*, p13.

and various overarching strategies and management plans. This is complemented with additional information from the following supporting documents:

- 01.01.01 – *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
Ergon Energy's Journey to the Best Possible Price	0A.01.02	Best Possible Price
Informing our plans, Our Engagement Program	0A.01.04	Engagement Program
Operating Forecast Expenditure Summary Document	06.01.01	Opex forecast summary
System Related Operating Expenditure Forecasting Summary	06.01.02	System related operating expenditure summary
Step Changes for Operating Costs	06.01.04	Step changes
Meeting Rule Requirements for Expenditure Forecasts	06.01.05	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
Ergon Energy Debt Transaction Costs 30 June 2014	06.02.04	Incenta Report Debt Transaction Costs
Our Capital Governance and our plans, policies and procedures	07.09.17	Governance, Plans, Policies and Procedures

Appendix B:

Capital expenditure forecasts for Standard Control Services

Introduction

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 \$3.6 billion. Changes have also occurred to the classification of services.

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 14% lower than the actual capital expenditure we expect to incur in the current regulatory control period 2010-15. The total capital expenditure Ergon Energy requires to meet the capital expenditure objectives in the next regulatory control period is provided below.

Table 41: Forecast capital expenditure, 2015-20⁸⁶

\$'000 (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Capital expenditure	769,615	753,576	691,278	677,404	663,418	3,555,291

This appendix outlines:

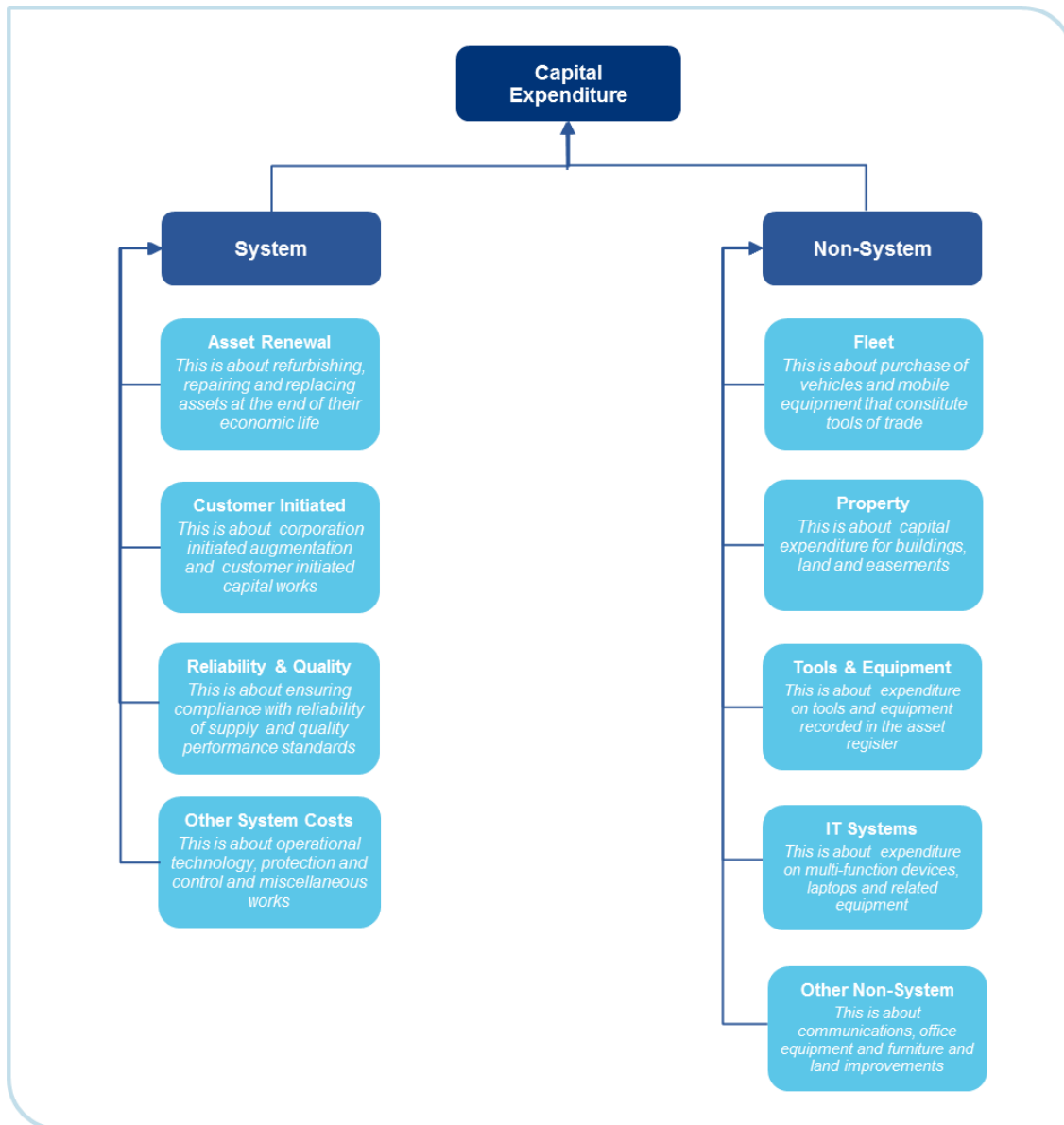
- why Ergon Energy incurs this level of capital expenditure, and the various categories of expenditure that make up Ergon Energy's capital program
- our level of capital expenditure in the current regulatory control period and how it compares to the efficient level of capital expenditure set by the AER for that period
- factors influencing our capital expenditure in the next regulatory control period, 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 operating expenditure forecasts satisfy the capital expenditure criteria, having regard to the factors outlined in the NER.

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 13 and discussed further below.

⁸⁶ 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 13: 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 document⁸⁷ 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 exceed our network’s existing capacity and fail to comply with our security of supply requirements,

⁸⁷ 07.00.01 – Asset Renewal Expenditure Forecast Summary.

MSS and requirements of the NER and *Electricity Act 1994 (Qld)*. Our *CIA Expenditure Forecast Summary* supporting document⁸⁸ 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 document⁸⁹ 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 document⁹⁰ 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 document⁹¹ 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 *Fleet Expenditure Forecast Summary* supporting document⁹²)
- **IT System capital expenditure** – expenditure on multi-function devices, laptops and related equipment that are not provided by SPARQ (refer to *ICT Expenditure Forecast Summary* supporting document⁹³)
- **Property capital expenditure** – non-system capital expenditure for buildings, land and easements (refer to *Property Expenditure Forecast Summary* supporting document⁹⁴).

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 the categories of tools and ladders. Expenditure on communications, office equipment and

⁸⁸ 07.00.02 – Ergon Energy CIA Expenditure Forecast Summary.

⁸⁹ 07.00.03 – Ergon Energy Customer Connection Initiated Capital Works Expenditure Forecast Summary.

⁹⁰ 07.00.05 – Ergon Energy Reliability and Quality of Supply Expenditure Forecast Summary.

⁹¹ 07.00.04 – Ergon Energy Other System and Enabling Technologies Expenditure Forecast Summary.

⁹² 07.00.06 – Ergon Energy Fleet Expenditure Forecast Summary.

⁹³ 07.00.07 – Ergon Energy ICT Expenditure Forecast Summary.

⁹⁴ 07.00.08 – Ergon Energy Property Expenditure Forecast Summary.

furniture as well as land improvements which are not allocated to a specific category of expenditure are also included in the overall forecast.

Table 42 provides Ergon Energy's forecast capital expenditure for each year of the next regulatory control period, disaggregated by program of expenditure.

Table 42: Proposed capital expenditure, 2015-20

\$'000 (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Asset Renewal	255,606	286,325	255,677	282,134	278,322	1,358,064
Corporation Initiated Augmentation	171,365	173,955	177,551	132,239	135,381	790,490
Customer Connection Initiated Capital Works	219,082	225,999	239,416	249,149	255,290	1,188,935
Reliability and Quality of Supply	3,361	3,400	3,527	3,603	3,638	17,528
Other System	42,070	31,050	20,613	29,432	25,708	148,872
Non-System	177,552	136,598	105,625	97,698	85,869	603,341
Gross capital expenditure	869,035	857,326	802,408	794,254	784,208	4,107,231
<i>less Alternative Control Services customer contributions</i>	<i>(99,420)</i>	<i>(103,750)</i>	<i>(111,130)</i>	<i>(116,850)</i>	<i>(120,790)</i>	<i>(551,940)</i>
Standard Control Services gross capital expenditure	769,615	753,576	691,278	677,404	663,418	3,555,291
<i>less Standard Control Services customer contributions</i>	<i>(29,750)</i>	<i>(30,390)</i>	<i>(31,860)</i>	<i>(32,860)</i>	<i>(33,400)</i>	<i>(158,260)</i>
Standard Control Services net capital expenditure	739,865	723,186	659,418	644,544	630,018	3,397,031

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).

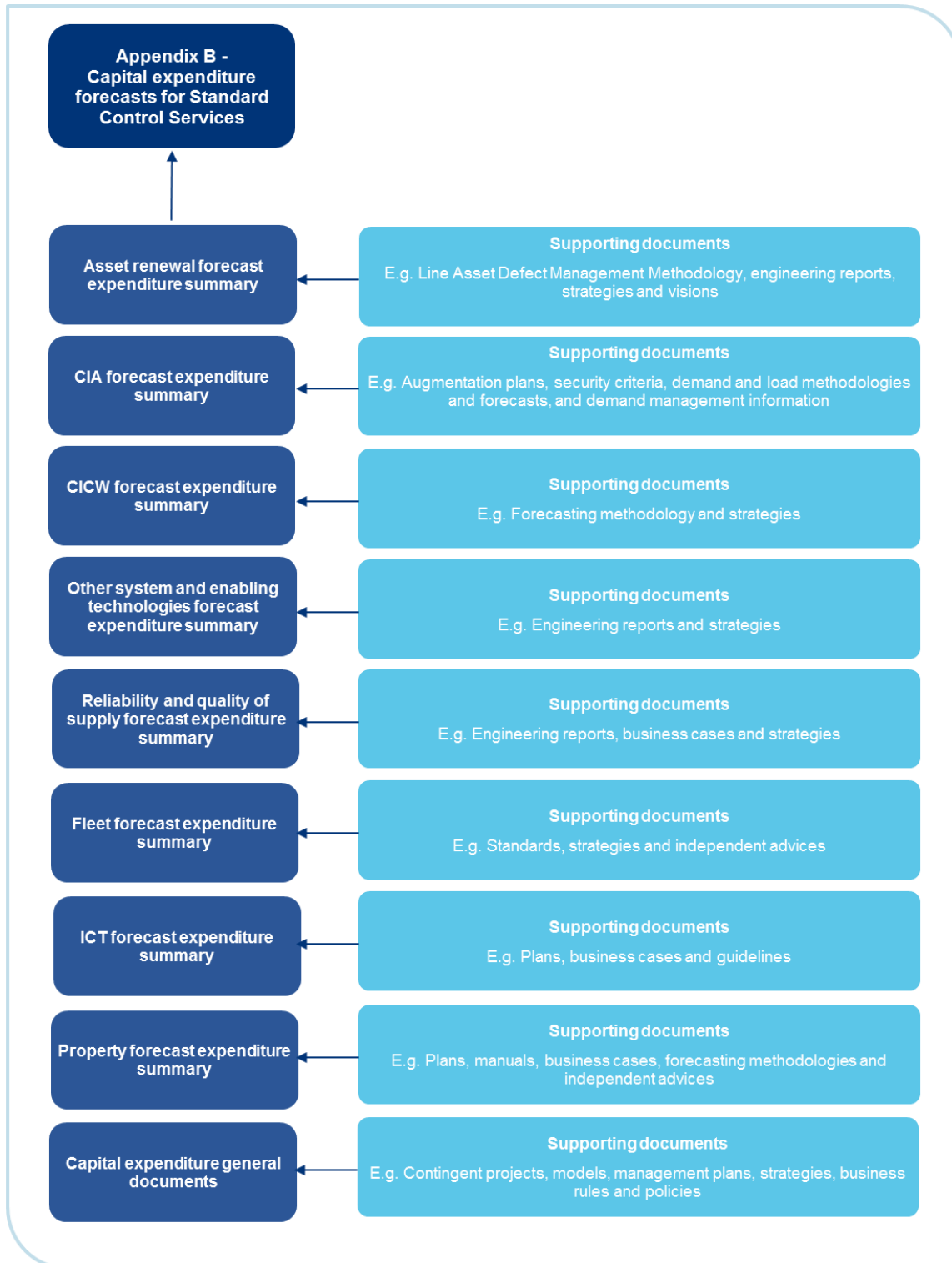
The 'net capital expenditure' above reflects our forecast of capital expenditure that is not otherwise funded through customer contributions, and therefore required to be funded through our revenue cap and DUOS charges.

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 14 below outlines the relationship between this Appendix and other supporting documentation.

The remainder of this appendix covers expenditure at the total level.

Figure 14: Capital expenditure documentation suite



3 Prior and current period performance

Table 43 and Table 44 provide Ergon Energy's actual expenditure for each year of the previous and current regulatory control periods, disaggregated by program of expenditure.⁹⁵

For comparison purposes, we have categorised this information in the same way as the capital expenditure forecast set out Table 41. Information provided for both regulatory control periods are based on the CAM applying in the current regulatory control period.

Table 43: Prior period capital expenditure by category, 2005-10⁹⁶

\$'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
Gross capital expenditure	821,350	933,384	944,129	935,016	790,148	4,424,028
<i>less Alternative Control Services customer contributions</i>	0	0	0	0	0	0
Standard Control Services gross capital expenditure	821,350	933,384	944,129	935,016	790,148	4,424,028
<i>less Standard Control Services customer contributions</i>	(45,692)	(51,887)	(83,333)	(107,879)	(67,290)	(356,080)
Standard Control Services net capital expenditure	775,659	881,497	860,796	827,137	722,859	4,067,948

⁹⁵ NER, S6.1.1(6).

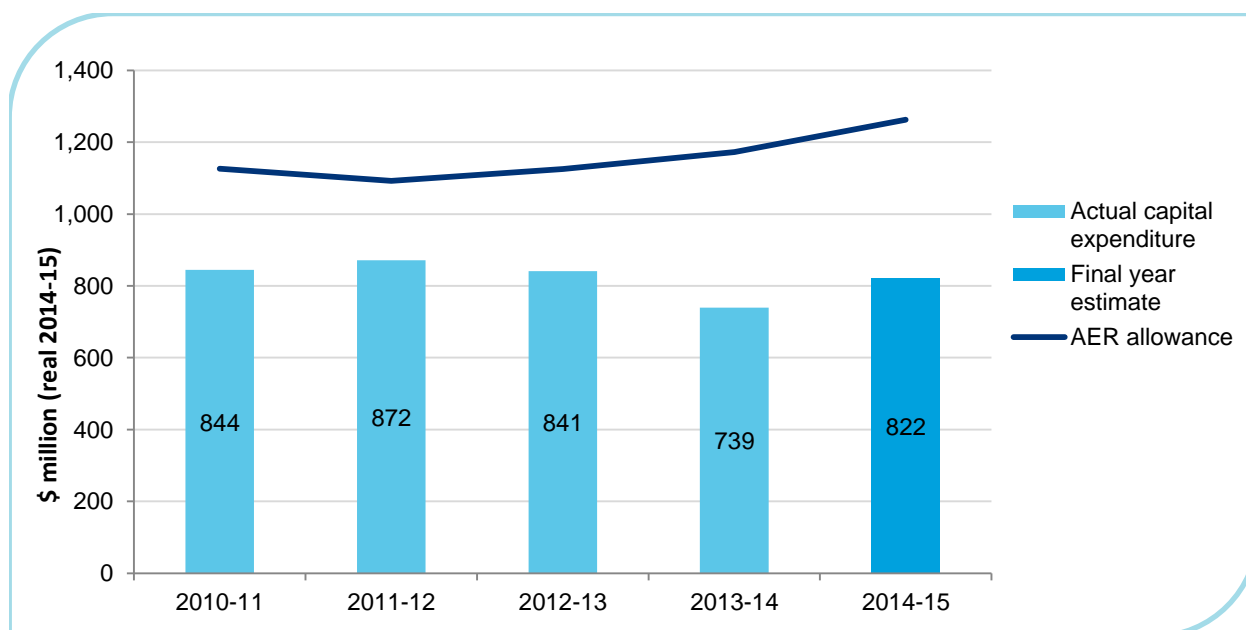
⁹⁶ Figures may not directly reconcile to figures set out in supporting documents due to differences in source data and assumptions.

Table 44: Current period 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	240,719	1,255,262
Corporation Initiated Augmentation	148,225	175,096	152,173	165,888	167,497	808,880
Customer Connection Initiated Capital Works	204,234	197,787	209,593	207,267	227,004	1,045,886
Reliability and Quality of Supply	22,327	28,275	24,577	32,868	51,487	159,534
Other System	84,657	56,464	37,934	35,932	44,054	259,042
Non-System	156,394	149,502	135,604	95,124	123,107	659,731
Gross capital expenditure	844,208	873,792	849,552	766,914	853,868	4,188,335
<i>less Alternative Control Services customer contributions</i>	<i>0</i>	<i>(2,248)</i>	<i>(8,914)</i>	<i>(27,729)</i>	<i>(31,950)</i>	<i>(70,841)</i>
Standard Control Services gross capital expenditure	844,208	871,544	840,638	739,186	821,918	4,117,494
<i>less Standard Control Services customer contributions</i>	<i>(75,854)</i>	<i>(59,023)</i>	<i>(71,117)</i>	<i>(61,340)</i>	<i>(86,220)</i>	<i>(353,553)</i>
Standard Control Services net capital expenditure	768,354	812,521	769,521	677,845	735,698	3,763,940

Figure 15 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 15: Comparison of capital expenditure, 2010-15



3.1 Expenditure outcomes in the previous period (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.⁹⁷ Additional network investment was required from 2004, to meet the higher reliability standards introduced in response to the Electricity Distribution Service Delivery (EDSD) Review.⁹⁸

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 current 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 the current period (2010-15)

As outlined in earlier sections of this Appendix, we expect our total capital expenditure for the current regulatory control period 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 Cyclone Yasi and Oswald.

During the current regulatory control period, 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 improved pricing outcomes for consumers and reduce the level of network capital investment required in the long term.

⁹⁷ Ergon Energy (2007), *Annual Report 2006-07*, p19.

⁹⁸ Our supporting document *0A.01.02 – Ergon Energy's Journey to the Best Possible Price* provides further detail.

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 period 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 \$1.6 billion (real \$2014-15) less than the AER approved total capital expenditure allowance.

As we head towards the start of the regulatory control period 2015-20, we are also continuing to make sure we position our expenditure in 2014-15 to ensure we deliver on our customer commitments for the current regulatory control period and to deliver the best possible price outcome for the start of the next regulatory control period.

Consistent with our gated governance investment framework, we will continually review and scrutinise the quantum and timing our future investment needs and priorities for the 2014-15 year. Investments planned in 2014-15 will be reviewed against a range of criteria including NER requirements, the impact of the ongoing process of transitioning to our new security criteria, safety net and Value of Customer Reliability approach, safety, compliance and applicable external factors and market conditions.

As a result, there is the potential for further prudent and efficient deferrals of investment to occur in the remainder of the 2014-15 year. Our expenditure priorities may also shift as we make efficient capital and operating expenditure trade-offs and there is also the potential for roll-ins and roll-outs of projects or programs to occur to address priority investment needs and safety and compliance requirements.

We will ensure that we update the AER and our customers and stakeholders on any key changes in our forecast capital expenditure for the 2014-15 year to support our best possible price commitment.

The following parts of this Section 3 contain greater detail on our performance during the current regulatory control period and the challenges we faced.

3.3 Changes to the external environment from 2010

Within 12-18 months of the current regulatory control period 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).⁹⁹

⁹⁹ Queensland Commission of Audit (2013), *Final Report – Volume 2*, February 2013, p5.

- the subsequent high \$AUD dampened trade-exposed economic activity, particularly in the manufacturing sector.

3.4 Affordability, customer concerns and how it resulted in reduced expenditure in the current 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 prices¹⁰⁰ 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 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 consumers 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.¹⁰¹ 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 2010-15.¹⁰²

¹⁰⁰ Notified Prices for 2012-13 were the first set of retail tariffs that had been determined on the basis of the N+R methodology.

¹⁰¹ Ergon Energy (2011), *Submission to the Electricity Network Capital Program Review – Somerville Review Panel*, 31 October.

¹⁰² Ergon Energy identified capital savings totalling \$930 million over the current regulatory control period 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)

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 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 consumers
- Queensland has a viable, sustainable and competitive electricity industry
- electricity is delivered in a financially sustainable manner from the Queensland Government’s perspective.

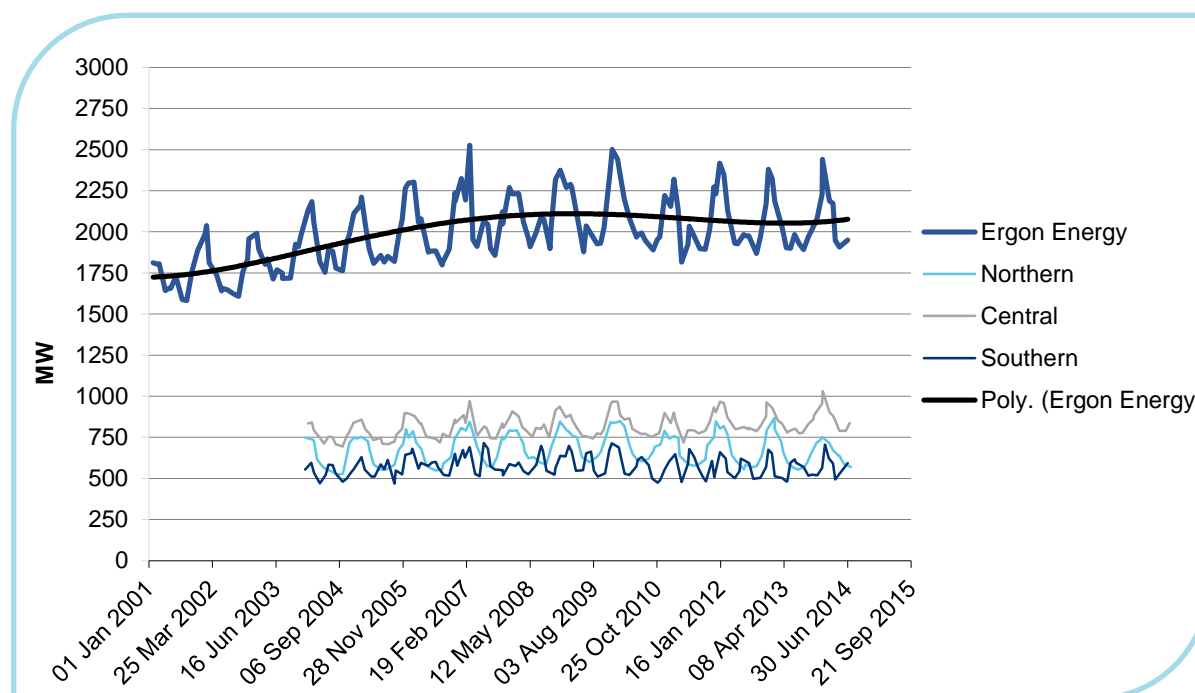
In response, we undertook an additional review of our program of works and further reduced our capital expenditure.

3.5 Our performance outcomes

Maximum (or peak) demand

Our maximum demand during the current regulatory control period has remained steady – significantly less than either we or the AER anticipated. Figure 16 shows the trend in our monthly maximum demand since 2001 in total and across our northern, central and southern regions.

Figure 16: Monthly maximum demand



In the current regulatory control period, 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 (GFC) 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 45 shows that our customer connection numbers have increased by 1.62% per annum for the four years of the current regulatory control period 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 45: Customer numbers, 2011-14

	2011	2012	2013	2014
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 current regulatory control period of 1.58%, which we detailed in our Regulatory Proposal for 2010-15.¹⁰³

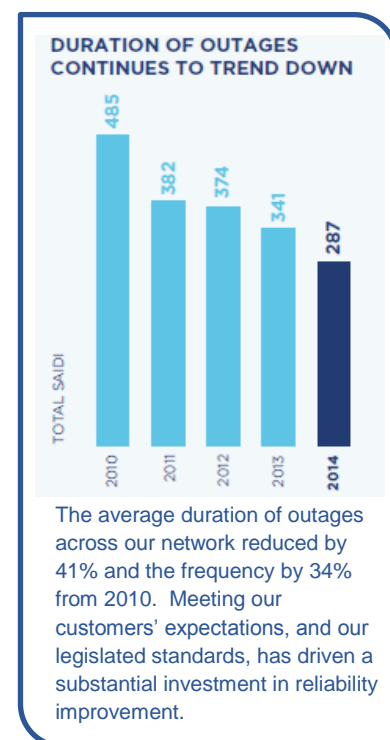
Asset age

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.



¹⁰³ 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.

We now see our challenge being 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.

Up until 1 July 2014, the Queensland Electricity Industry Code set out the MSS levels that we must meet for our reliability performance.¹⁰⁴ These are expressed as annual targets for our urban, short rural and long rural feeders for the duration and frequency of interruptions (expressed as SAIDI and SAIFI).

Table 46 shows that we met all of our MSS limits between 2010-11 and 2013-14 for the frequency of interruptions and five of our six MSS limits for the duration of interruptions. The duration of long rural interruptions has been the only measure marginally unfavourable against the MSS limit. This was caused by the extended aftermaths of tropical cyclones and floods, where we needed to take precautionary action to ensure the safety of staff and customers.

Table 46: Reliability performance, 2010-14

		SAIDI				SAIFI			
		2010-11	2011-12	2012-13	2013-14	2010-11	2011-12	2012-13	2013-14
Urban	MSS	149	148	147	146	1.98	1.96	1.94	1.92
	Actual	148.88	136.28	135.12	118.49	1.628	1.413	1.493	1.394
Short rural	MSS	424	418	412	406	3.95	3.9	3.85	3.8
	Actual	425.74	391.95	341.44	291.91	3.532	3.549	2.977	2.767
Long rural	MSS	964	948	932	916	7.4	7.3	7.2	7.1
	Actual	827.35	1041.58	951.53	798.42	5.266	7.019	6.246	6.118

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 current regulatory control period 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 47 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 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.

¹⁰⁴ The MSS levels are currently prescribed in our Distribution Authority.

Table 47: Quality of supply complaints, 2010-2014

Year	Quality of Supply complaints	Solar issue complaints	Non-solar complaints
2009-10	1,121	32	1,089
2010-11	950	71	879
2011-12	975	147	828
2012-13	1,398	592	806
2013-14	817	307	510

Our commitment to seeking alternatives to augmentation investment

We reduced demand management through initiatives aimed at constrained areas of the network. As we entered 2014-15, the final year of the current regulatory control period, we surpassed our five-year demand management target, delivering 126MVA in demand reductions, which deferred or avoided \$644 million in capital investment.

Necessary emergency response for significant weather events

A number of significant weather events affected expenditure in the current regulatory control period. Major restoration works were associated with Tropical Cyclones Anthony (2012), Yasi (2011), Oswald (2012), Ita (2014) and the flooding around the Bundaberg and Southern regions of Ergon Energy.

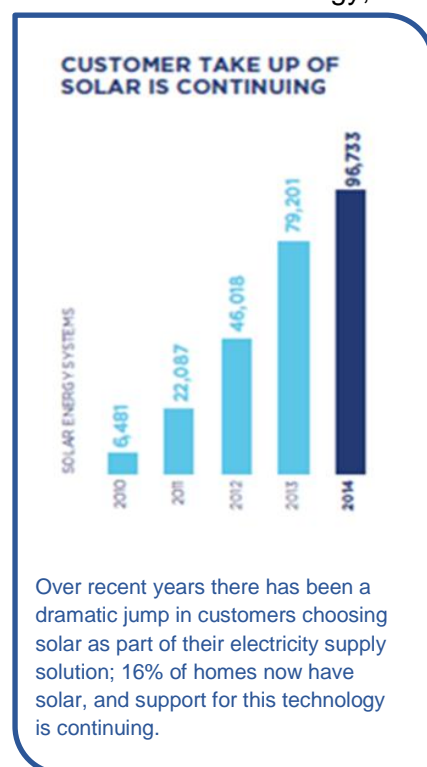
Over this period we have been investing in our network and people to uphold our commitment to “being there after the storm”. These initiatives include hardening the asset base (e.g. undergrounding assets, cost effective elevation of substations), developing advanced monitoring and real time data collection 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 six 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. Fifteen 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 next regulatory control period:

- 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 next regulatory control period.

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, 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.

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.¹⁰⁵

Existing obligations, rules requirements, plans, policies and procedures

Our capital expenditure forecasts for the next regulatory control period 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 and various overarching strategies and management plans. This is complemented with additional information from the following supporting documents:

- *01.01.01 – 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 current regulatory control period have led to our service and price performance to customers. We have asked our customers what they are looking for in the next regulatory control period. Our commitment to what customers want, in addition to ensuring we can

¹⁰⁵ 0A.02.01 – Ergon Energy Expenditure Benchmarking.

meet relevant requirements of the NER and other regulatory obligations, is largely driving the expenditure program in the next regulatory control period.

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. 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 don't want to risk the network deteriorating, 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 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 – 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 – Asset Renewal Expenditure Forecast Summary*
- *07.00.02 – CIA Expenditure Forecast Summary*
- *07.00.03 – Customer Connection Initiated Capital Works Expenditure Summary*
- *07.00.05 – 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'll 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 – Asset Renewal Expenditure Forecast Summary*
- *07.00.06 – 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 – Other System and Enabling Technologies Expenditure Forecast Summary*
- *07.00.07 – 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 126MVA demand reductions to date over the current regulatory control period 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 – Other System and Enabling Technologies Expenditure Forecast Summary*
- *07.00.07 – 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 Methodology¹⁰⁶ 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 current regulatory control period, and concerns raised by the AER on our previous forecasting approach and how we have addressed them.

5.1 Current period forecasting

AER approach

In the current regulatory control period, 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.

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 for the last two years of the current period (i.e. 2013-14 and 2014-15) and the five years of the next regulatory control period. 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 next regulatory control period and in future periods
- corporate and stakeholder expectations and commitments in respect of price and service delivery

¹⁰⁶ Refer to <https://www.ergon.com.au/network/network-management/future-investment/future-direction>.

- compliance with the NER and state imposed regulatory obligations
- current workforce delivery and capacity to deliver works in the next regulatory control period.

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.

The assumptions below have been certified by the directors of Ergon Energy, as required by the NER.¹⁰⁷

Table 48: 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. The potential for future changes arising from recent announcements regarding the Queensland Government's Strong Choices Plan that could see the assets of distribution networks being subject to a leasing arrangement have not been factored into our expenditure assumptions for the regulatory control period 2015-20.

¹⁰⁷ Refer to supporting document 06.01.06 – Certification of reasonableness – expenditure forecast assumptions.

Assumption	Application
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.
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	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

Assumption	Application
requirements will not be materially disrupted by extreme weather events.	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). ¹⁰⁸ 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 current regulatory control period. We have implemented a range of measures to address these concerns, as shown in Table 49.

Table 49: 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
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

¹⁰⁸ 06.02.02 – Jacobs: Cost Escalation Factors 2015-20.

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 current regulatory control period.

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 next regulatory control period 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.

We forecast **Fleet capital expenditure** by using the results of a simulation model which forecasts the entry and exit of vehicles from the Ergon Energy fleet. This model, a dynamic system model, is run separately for all vehicle types and caters for usage, ageing and accidents. The model is calibrated for the anticipated number of personnel and the different types of vehicles that are required to meet demand. The results from the model are a vehicle by vehicle lifecycle from procurement through to retirement. The main parameters in the model are the type of vehicle required for each task, the method of procurement (lease versus buy) and the retirement point; each of these elements has been specifically reviewed to ensure prudence and efficiency.

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 – Unit Cost Methodologies Summary for Ergon Energy* and *07.09.01 – 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)¹⁰⁹ and fleet¹¹⁰ 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

We develop a cost estimate for all major projects (i.e. greater than \$1 million) 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 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.

¹⁰⁹ *07.07.03 – ICT Forecasting Method and Approach.*

¹¹⁰ *07.00.06 – Ergon Energy Fleet Expenditure Forecast Summary.*

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 that we take 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. Our delivery plan indicates that 17% of our work will be outsourced to contractors. We apply appropriate mobilisation and cost uplift factors that are applicable to the use of contractors.

6 Outcomes for customers

As a result of our investments, we are committing to the customer benefits shown in Table 50.

Table 50: Customer benefits and related risks

Customer benefit	Related risks
Our approach to safety	
<ul style="list-style-type: none"> • Our goal is for our safety performance to stand with the best in our industry... to be Always Safe. • Our expenditure on renewal, maintenance and network operations are all focused on managing safety risks. 	<ul style="list-style-type: none"> • Unforeseen safety related issues or damage caused by weather events may arise in the next period that may result in the reprioritising of expenditure towards addressing them or lead to passing on cost increases in the period following.

Customer benefit	Related risks
A reliable, quality electricity supply	
<ul style="list-style-type: none"> 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. 	<ul style="list-style-type: none"> 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. Improvements in the areas of the network currently requiring attention will need to be prioritised based on the level of available funds. 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.
Our disaster response	
<ul style="list-style-type: none"> We'll be there after the storm, prepared and with the resources to respond to whatever Mother Nature delivers. 	<ul style="list-style-type: none"> If approved, the operational resourcing levels outlined in our proposal will maintain our current emergency response capability.
Meeting service expectations	
<ul style="list-style-type: none"> We'll meet our guaranteed services commitments. If we don't, we'll pay you. 	<ul style="list-style-type: none"> As expectations around choice and control evolve, our service standards, especially in the connections and communications area may need to be reviewed.
A future of customer choice	
<ul style="list-style-type: none"> We're looking to the future – and evolving the network to best support customer choice in economic electricity supply solutions. 	<ul style="list-style-type: none"> 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.
The best possible price	
<ul style="list-style-type: none"> We're targeting to reduce what we charge for the use of the network in 2015-16, and keep increases overall in network charges under inflation for the five years. By separating metering service charges from our network charges, we are supporting customer choice in providers. 	<ul style="list-style-type: none"> 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. For customers on regulated retail prices (Notified Prices) the actual price impact of Ergon Energy's Regulatory Proposal will depend on the approach the QCA takes in setting prices in the future. 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.

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 – 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.

8 Supporting documentation

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

Name	Ref	File name
Ergon Energy's Journey to the Best Possible Price	0A.01.02	Best Possible Price
Ergon Energy Expenditure Benchmarking	0A.02.01	Ergon Benchmarking
Legislative and Regulatory Obligations and Policy Requirements	01.01.01	Legislative and Regulatory obligations
Meeting Rule Requirements for Expenditure Forecasts	06.01.05	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
Asset Renewal Expenditure Forecast Summary	07.00.01	Asset Renewal Expenditure Forecast Summary
CIA Expenditure Forecast Summary	07.00.02	Corporation Initiated Augmentation Expenditure Forecast Summary
Customer Connection Initiated Capital Works Expenditure Forecast Summary	07.00.03	Customer Initiated Capital Works Expenditure Forecast Summary
Other System and Enabling Technologies Expenditure Forecast Summary	07.00.04	Other System Enabling Technologies Expenditure Forecast Summary
Network Reliability and Quality of Supply Expenditure Forecast Summary	07.00.05	Reliability and Quality of Supply Forecast expenditure Forecast Summary
Fleet Expenditure Forecast Summary	07.00.06	Fleet expenditure forecast summary
ICT Expenditure Forecast Summary	07.00.07	ICT expenditure forecast summary
Property Expenditure Forecast Summary	07.00.08	Property expenditure forecast summary
Unit Cost Methodologies for Ergon Energy Summary	07.00.09	Unit Cost Methodologies summary
ICT Forecasting Method and Approach	07.07.03	Expend Forecast Method 2015-2020 Indiv Business Unit ICT
Network Capex Summary Model	07.09.01	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

Appendix C: Rate of Return

Introduction

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.

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 placeholder allowed rate of return of 8.02% in our Regulatory Proposal is a reduction on the current period's 9.72% and the 8.50% rate set in the prior period (under the regulation of the QCA).

This supports our target to reduce what we charge for the use of our network in 2015-16, and keep increases overall in network charges under inflation for the next five years.

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 included a placeholder estimate of 8.02% (nominal) for the rate of return based on market conditions at the time our proposal was finalised. In doing so, we have been able to meet our 'best possible price' commitment outlined in *0A.00.01 – An Overview, Our Regulatory Proposal 2015-20*. To the extent that our financing costs continue to improve relative to the assumptions contained in our proposal, we expect 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.

1.1 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.¹¹¹

As an asset intensive business, Ergon Energy's financing requirements are substantial. Table 51 sets out the assumed funding requirements for Ergon Energy at the beginning of the regulatory control period.

Table 51: Assumed funding requirements, \$m¹¹²

Assumed financing requirement represented by Opening RAB	\$10,041.54
Investment requiring debt financing	\$6,024.93
Investment requiring equity financing	\$4,016.62

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 Australian Energy Market Commission (AEMC) in the context of the 2012 Rule change process:¹¹³

¹¹¹ NER, clause 6.5.2(a).

¹¹² Assumes capital structure consistent with the AER's Rate of Return Guideline.

¹¹³ AEMC (2012), *Final Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, pp.ii-iii.

“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.”

In the current regulatory control period, 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.¹¹⁴ The AEMC has acknowledged that:¹¹⁵

“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.”

The AER has also noted the adverse consequences of a rate of return set too high or too low:¹¹⁶

“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 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.”

¹¹⁴ 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.

¹¹⁵ AEMC (2012), *Ibid*, p44.

¹¹⁶ AER (2013a), *Better Regulation: Rate of Return Fact Sheet*, December 2013.

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:¹¹⁷

“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.”

In reporting to the Ministerial Council on Energy as part of its review of energy network pricing, the Expert Panel found:¹¹⁸

“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.”

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 EDSD review), which concluded:¹¹⁹

“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 Panel believes that the networks have not had sufficient expenditure outlaid on them to adequately maintain them and to meet increased demand from growth...”

¹¹⁷ Productivity Commission (2001), *Review of the National Access Regime, Report no. 17*, AusInfo, Canberra, p83.

¹¹⁸ Expert Panel on Energy Access Pricing (2006), *Report to the Ministerial Council on Energy*, April 2006, p77.

¹¹⁹ Independent Panel (2004), *Detailed Report of the Independent Panel, Electricity Distribution and Service Delivery for the 21st Century*, p8.

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 AEMC¹²⁰ and AER.¹²¹

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 AEMC¹²² and AER,¹²³ this is also consistent with the principle of competitive neutrality, which underpinned the corporatisation of government-owned businesses, including Ergon Energy.

In 2014, the Queensland Government released its Strong Choices strategy, which includes plans to introduce private sector funding of the electricity network businesses. For Ergon Energy, this contemplates:¹²⁴

- State responsibility for corporation debt being progressively removed from the State's balance sheet
- potential for the private sector to directly fund future capital expansions or to finance current investment through a long-term lease
- increased private sector involvement in Ergon Energy's investment decision-making processes.

The Queensland Government intends to take this plan to the next election.

While Ergon Energy's allowed rate of return has always been set with reference to an efficient private sector benchmark, the Government's announcement highlights the fact that Ergon Energy expects to be competing with other businesses in the infrastructure sector for scarce capital.

1.2 Legislative context

The regulatory framework in relation to the provision of Standard Control Services to our customers is contained in the NEL. The Revenue and Pricing Principles¹²⁵ allow us to "at least" recover the efficient costs of providing these services.

One of these 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.

¹²⁰ AEMC (2012). Ibid.

¹²¹ AER (2013b), *Better Regulation, Explanatory Statement, Rate of Return Guideline*, December 2013.

¹²² AEMC (2012), Ibid, p79.

¹²³ AER (2013b), Ibid, p211.

¹²⁴ Queensland Government (2014), *The Strongest and Smartest Choice, Queensland's Plan for Secure Finances and a Strong Economy*.

¹²⁵ NEL, clause 7A.

The NER now requires the allowed rate of return to achieve the following objective (the ‘allowed rate of return objective’):¹²⁶

“...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*...”

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.¹²⁷

1.3 The Rate of Return Guideline

Recent amendments to the NER for the estimation of the allowed rate of return recognise the important role the rate of return plays in attracting the necessary funds from capital markets for these investments. The new arrangements address the need for sufficient flexibility to ensure the allowance for the return is appropriate, based on careful consideration of relevant estimation methods, financial models, market data and other evidence.¹²⁸

To provide NSPs with some degree of certainty as to how the AER is likely to apply these provisions, the NER provides for the AER to make and publish Rate of Return Guidelines.¹²⁹ The AER’s approach to estimating the allowed rate of return is summarised in Figure 17.

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. We highlight the areas where the AER should depart from its Guideline and the reasons why in the relevant parts of this Appendix.

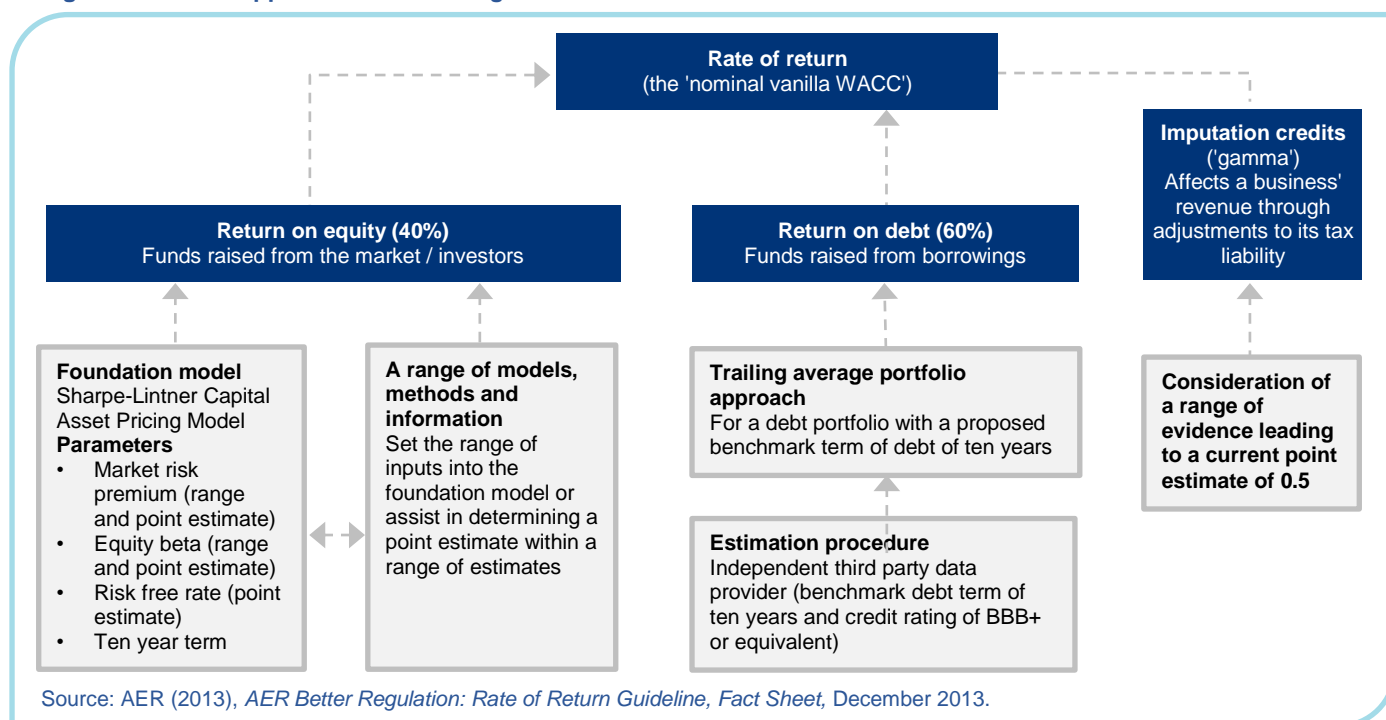
¹²⁶ NER, clause 6.5.2(c).

¹²⁷ AEMC (2012), p12.

¹²⁸ AEMC (2012), *ibid*, piii.

¹²⁹ NER, clause 6.5.2(m).

Figure 17: AER’s approach to estimating the allowed rate of return



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.¹³⁰ Assuming 60% gearing, the proposed estimate for the first year of the regulatory control period is provided in Table 52 below.

Table 52: Summary of key rate of return parameters, 2015-20¹³¹

Key parameter	Ergon Energy's calculation
Return on equity	10.53%
Return on debt	6.36%
Rate of return	8.02%

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 Final Determination.

The return on debt will then be updated annually during the regulatory control period in accordance with the trailing average approach,¹³² based on averaging periods to be agreed with the AER. For

¹³⁰ 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.

¹³¹ To calculate the WACC, the return on equity value has been rounded to 10.5%, consistent with the PTRM.

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 4.2 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 53, including identifying where Ergon Energy has departed from the AER's Rate of Return Guideline.

Table 53: 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"> The AER's starting point is the standard Sharpe-Lintner Capital Asset Pricing model (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 Estimate to be applied for the duration of the regulatory control period 	<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. If the AER rejects our departure from the Guideline, an alternative approach is outlined in Section 3.5.</p>
Return on Equity: Risk free rate	<ul style="list-style-type: none"> Observed yield on 10 year Commonwealth Government bonds 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 	<p>Ergon Energy's proposed approach complies with the AER's Rate of Return Guideline. For the purpose of this Regulatory Proposal, Ergon Energy's proposed risk free rate is 3.63%, which is the average over the 20 business days to 11 July 2014.</p> <p>It is understood that this will be updated for the AER's Final Distribution Determination. It is assumed that any material changes in prevailing market conditions at the time the risk free rate is reset would also necessitate a review of the market risk premium (MRP).</p>
Return on Equity: Market Risk Premium	<ul style="list-style-type: none"> 10 year forward looking estimate commensurate with prevailing conditions in the market for funds at the commencement of the regulatory control period Evidence to be considered includes historical excess returns, dividend 	<p>Ergon Energy has departed from the AER's Rate of Return Guideline to estimate the MRP. This is because we do not consider that the evidence relied upon by the AER will result in a return on equity estimate that satisfies the requirements of the NER and the allowed rate of return objective.</p>

¹³² 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
	<p>growth model, survey evidence, implied volatility and recent regulatory determinations</p>	<p>Our estimate is instead based on historical excess returns, the Wright approach, the Dividend Discount Model and independent valuation reports. As at 11 July 2014, this results in an estimate of 7.57%.</p>
<p>Return on Equity: Equity beta</p>	<ul style="list-style-type: none"> • To be estimated using empirical analysis, which focuses on a small sample of domestic energy network businesses • International comparators and the Black CAPM will inform where the point estimate is selected from within the range • The AER's preferred value is 0.7. 	<p>Ergon Energy has departed from the AER's Rate of Return Guideline to estimate beta. This is because we consider that the AER's approach to estimating beta is deficient as it fails to take into account relevant current market evidence.</p> <p>The AER's decision to exclude international comparators from its beta sample, but use them to inform where the point estimate is selected from within the range, materially underweights the contribution this data should be given to the beta estimate. The CAPM beta has therefore been re-estimated to include these firms in the sample. The resulting estimate is 0.82.</p> <p>If the AER rejects the multi-model approach and applies the SL CAPM only, Ergon Energy submits that the equity beta estimate applied in that model needs to be set at 0.91 in order to arrive at an estimate of the return on equity that satisfies the requirements of the NER.</p>
<p>Rate of return on debt</p>	<ul style="list-style-type: none"> • BBB+ credit rating assumption • Based on historical trailing average portfolio approach, assuming one-tenth of the debt portfolio is refinanced each year (simple averaging approach) • Transitional formula will apply for the first ten years • Data used to produce the estimate will be sourced from an independent third party provider • 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 	<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"> • adoption of the trailing average approach, with a transition • use of an independent third party provider to estimate the return on debt • nomination of our proposed averaging periods for each year of the regulatory control period. <p>Ergon Energy has departed from the Rate of Return Guideline in the following areas:</p> <ul style="list-style-type: none"> • <i>the notional credit rating assumption:</i> the AER's BBB+ assumption was arrived at having regard to over 10 years of credit rating data. In the case of credit ratings, Ergon Energy disagrees that such a long horizon is necessary and instead, considers that this could be misleading. Focusing on more recent data (the last five years) would indicate that the appropriate assumption is BBB, which is what Ergon Energy has applied in this proposal. • <i>the averaging approach:</i> instead of a simple average, Ergon Energy is

Allowed rate of return component / parameter	Rate of Return Guideline approach/value	Ergon Energy's proposal and identified departures
		<p>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.</p> <p>Ergon Energy has used data from the Reserve Bank of Australia (RBA) to estimate the debt risk premium. Because the RBA's ten year estimate reflects a term to maturity of less than 10 years, the estimate has been extrapolated to produce a 10 year estimate based on the slope of the RBA's yield curve. Ergon Energy has estimated the return on debt as the Australian Financial Markets Association (AFMA) swap rate plus the RBA's margin to swap.</p> <p>For the first year of the regulatory control period, the indicative risk free rate (for the cost of debt) and the debt risk premium reflects the mid-point of an averaging period that is between one and 12 months. The resulting estimate is 6.36%.</p>
Gearing ratio	<ul style="list-style-type: none"> Based on benchmark gearing ratio of 60% (debt to total value) 	Ergon Energy has proposed the Rate of Return Guideline value of 60%.
Allowed rate of return	<ul style="list-style-type: none"> Defined as a nominal vanilla Weighted Average Cost of Capital (WACC) 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 To be updated annually each year for adjustments to the rate of return on debt 	<p>The return on equity has been estimated based on the four relevant models specified above, applying weights that reflect the relative strengths and weaknesses of each model. This results in an estimate of 10.53%, which has been rounded to the nearest one decimal place consistent with the PTRM, resulting in an input value of 10.5%.</p> <p>Combining this with the return on debt of 6.36%, Ergon Energy's proposed WACC is 8.02% (post tax nominal vanilla).</p>
Imputation credits	<ul style="list-style-type: none"> Value of 0.5 assigned to imputation credits 	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

Ergon Energy has departed from the AER's Rate of Return Guideline in favour of an estimate that gives appropriate regard to relevant estimation methods, financial models, market data and other evidence, as required by the NER and contemplated by the AEMC as an outcome of its 2012 Rule change process. Our estimate reflects the return that an equity investor would require in committing funds to a firm with the same risk profile as the benchmark efficient entity, given prevailing market conditions. Our estimate for the return on equity therefore contributes to the achievement of the allowed rate of return objective.

As a Government Owned Corporation, Ergon Energy does not currently seek to attract equity funds from the market. However, as noted above, these arrangements may change in the future. The Queensland Government has recently announced it is exploring options for private sector involvement in financing Ergon Energy investments. While the NER has always observed the need for rates of return to be commensurate with prevailing market rates that reflect private sector benchmarks, 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.

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.¹³³

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. SFG also completed separate reports on the:

- Black CAPM¹³⁴
- Dividend Discount Model¹³⁵
- Fama-French model.¹³⁶

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. While the Rate of Return Guideline attributes some role to some of these alternative models and evidence, the AER intentionally starts with the SL CAPM as its Foundation Model. The effective outcome of applying this approach is that other models have little, if any, material weight.

Ergon Energy submits that the AER's approach, if applied in Ergon Energy's distribution determination, will produce a rate of return that fails to satisfy the requirements of clause 6.5.2 of the NER. If the AER's preferred Foundation Model is implemented in accordance with the Rate of

¹³³ 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 was updated to reflect more up-to-date market parameters. The addendum, 08.01.02 – *Updated estimate of the required return on equity*, is also attached to this Regulatory Proposal.

¹³⁴ 08.01.05 – SFG Consulting: *Cost of Equity in the Black Capital Asset Pricing Model* (SFG Report Black CAPM)

¹³⁵ 08.01.07 – SFG Consulting, *Alternative Versions of the Dividend Discount Model and the Implied Cost of Equity* (SFG Report Dividend Discount Model)

¹³⁶ 08.01.06 – SFG Consulting: *The Fama-French Model* (SFG Report Fama French)

Return Guideline, it will result in a return on equity that is too low in the current market environment. This will undermine rather than promote the allowed rate of return objective. For this reason, Ergon Energy has proposed a departure from the AER's Rate of Return Guideline. The form of this departure, and the reasons for it, are explained in more detail below.

3.1 The correct methodology for determining the expected cost of equity

Issues with the AER's approach

Findings of the AEMC's Rule change process

One of the most significant changes emerging from the rule change process concluded by the AEMC in 2012 was recognition of the role that other estimation methods, models, market data and other evidence should have in estimating the return on equity.¹³⁷ This role is not a peripheral or secondary one. Rather it recognised that:

“...no one method can be relied upon in isolation to estimate an allowed return on capital that best reflects benchmark efficient financing costs...”¹³⁸

In its Final Position Paper, the AEMC acknowledged the concerns that stakeholders expressed in relation to the proposed rule changes, which was that the regulator would still effectively be able to exclusively rely on the SL CAPM. It stated that:

“The Commission understands this concern is potentially of considerable importance given its intention is to ensure that the regulator takes relevant estimation methods, models, market data and other evidence into account when estimating the required rate of return on equity.”¹³⁹

However, in the interests of balancing prescription and flexibility, it resisted including a list of relevant models and evidence (which would be non-exhaustive), or assigning weights that should be applied to them.

In Ergon Energy's view, the intent of these changes to the NER and the AEMC's resistance to introduce prescription regarding the models and evidence was not to provide the regulator with the discretion to apply the same approach that it applied prior to the changes. However, this is effectively what the application of the AER's Rate of Return Guideline does in practice. To the extent that it proposes to refer to other models and evidence, they are assigned limited, if any, practical weight in terms of their impact on the overall outcome.

The AER states that the SL CAPM only provides the “starting point” and “will be used informatively, rather than determinately”.¹⁴⁰ Ergon Energy considers that this materially understates the role it plays in the AER's decision framework if the Guideline is applied.

¹³⁷ AEMC, Rule Determination, *ibid*

¹³⁸ AEMC, Rule Determination, *ibid*, p49.

¹³⁹ AEMC (2012), *ibid*, p39.

¹⁴⁰ AER (2013b), *ibid*, p.75.

The AER's Guideline does also specify a potential role for other market data and evidence in assessing the reasonableness of the return on equity estimated using the SL CAPM. While the AER suggests that this other data and evidence could cause it to depart from the SL CAPM estimate, it has considerable discretion here and the circumstances under which it might do so, and how such an adjustment would be made, without departing from the Guideline, remain unclear.

Overall, under the AER's Rate of Return Guideline the return on equity is still being set within the confines of the SL CAPM and the assumption that a firm's returns are fully explained by systematic risk. Further, it assumes that this relationship between risk and return is linear. As will be set out below, empirical tests of the CAPM have shown that it in fact produces estimates of expected returns that bear little relationship with actual returns, which could also mean that factors or risks that are priced by investors are ignored by the SL CAPM.

Limitations of the Sharpe-Lintner CAPM

There are a number of known limitations of the SL CAPM, which are addressed in detail in SFG's Cost of Equity Report.¹⁴¹ The key issues are summarised in the section below.

First, the SL CAPM's limiting assumptions have been acknowledged, including by the AER.¹⁴² The SL CAPM's limiting assumptions include:

- investors can undertake unlimited borrowing and lending at the risk free rate
- all investors have homogenous expectations
- there are perfect capital markets, with no taxes or transaction costs.

Second, the SL CAPM has performed poorly in empirical tests. In particular, there is consistent and strong evidence to show that the SL CAPM will tend to underestimate the return on equity for low beta stocks (or stocks that are less risky than the market) and overestimate the return for high beta stocks. The Black CAPM enhances the SL CAPM by relaxing its restrictive assumption that investors can borrow and lend at the risk free rate.

Third, as noted above, the SL CAPM models a linear relationship between risk and return, which assumes that the market portfolio must be efficient. If the market portfolio is not efficient, the relationship between risk and return will not be linear and the application of the SL CAPM will not result in estimates of expected returns that are a good predictor of actual returns.

SFG observes the consistent historical evidence that shows that certain portfolios have consistently outperformed the stock market across time and across markets. This is highly unlikely to occur if the market is (ex ante) efficient. As this consistent evidence has accumulated through time, this more likely suggests that rather than occurring by chance, this is occurring because of the presence of factors that are not reflected in the SL CAPM. The two key factors that have emerged from empirical tests are size and the book to market ratio. The Fama-French three factor model is an alternative asset pricing model that estimates expected returns as a function of systematic risk, along with size and book to market ratios. The use of this model is discussed further below.

¹⁴¹ 08.01.01 – SFG Consulting: *The Required Return on Equity for Regulated Gas and Electricity Network Businesses*.

¹⁴² The AER has specified a role for the Black CAPM in estimating the equity beta, which as noted below, as implemented by the AER results in that model having limited, if any, practical influence on the return on equity.

While the issues identified above are significant, given different asset pricing models have different strengths and weaknesses it is not proposed to discard the SL CAPM completely. However, it does not rationalise the AER continuing to provide it with the status of sole Foundation Model, while relegating other models to having a very limited practical role, or no role at all (in the case of the Fama-French Model).

As noted above, while the AER describes the SL CAPM as a “starting point”, this starting point is the SL CAPM defined range. This is also highly dependent on the way the SL CAPM is implemented and the market data and evidence that is relied upon (this is considered in more detail below in the context of examining each parameter).

At best, the AER has assigned some weight to the Dividend Discount Model in using it, alongside other evidence, to establish the range for the MRP in the SL CAPM. However, in acknowledging that it has some relevance to estimating the return on equity (although no weighting is specified relative to other models and evidence), its practical influence on the overall outcome remains limited and then only within the confines of one of the SL CAPM’s inputs. Ergon Energy notes that the AER’s current estimate of the MRP, which is 6.5%, was applied in previous determinations under the AER’s previous Statement of Regulatory Intent (following the commencement of the GFC).

The Black CAPM has also been used to inform where the AER selects the point estimate for beta within the SL CAPM range. It uses this, along with beta estimates from international firms, to justify selection of the point estimate from the upper bound of that range. This alternative model and market data is acknowledged as relevant but has no influence on the specification of the range itself. The AER had previously selected the beta estimate from the upper bound of its range in the absence of any acknowledgment of the Black CAPM, or this other evidence.

In summary, the AER’s Guideline does not give sufficient weight to the range of evidence available. Ergon Energy interpreted the AEMC’s process – and the consequent rule changes – as a fundamental turning point in the framework for determining the cost of equity giving more appropriate recognition to these other models and greater flexibility in how they are used in estimating the return on equity. Therefore, appropriate recognition of other models requires a departure from the Guideline.

Summary of concerns with application of the AER’s Rate of Return Guideline

The AER’s application of the SL CAPM as its Foundation Model therefore introduces two potential sources of error. The first is that the AER’s return on equity estimate is based on a model that has been shown to be a poor predictor of actual returns and ignores relevant factors and/or risks that explain returns. The second source of risk is that the parameters themselves are not correctly estimated.

Overall, the key question is whether the AER’s framework in the Rate of Return Guideline makes appropriate use of all relevant estimation methods, models, market data and other evidence to produce the best available estimate of the required return on equity in the current market based on the requirements of the NER. In Ergon Energy’s view, based on the arguments summarised above and the more detailed analysis and evidence contained in the accompanying SFG reports, it clearly does not.

This is of significant consequence. SFG’s analysis demonstrates that the SL CAPM produces a return on equity that is materially below the estimates produced by the other relevant models it has identified, being the Black CAPM, Fama-French Model and Dividend Discount Model, and indeed

is the 'outlier' of the four, producing an estimate that is well below the other three models. This in turn is likely to result in an estimate that is below the return required by investors in the current market environment, which will adversely impact the ability of the business to raise funds to undertake necessary investments.

Ergon Energy's proposal

SFG concluded that all four models (the SL CAPM, the Black CAPM, the Dividend Discount Model and the Fama-French model) have a relevant role to play in estimating the return on equity and that they all:

- have a sound theoretical basis
- have the purpose of estimating the required return on equity as part of the estimation of the cost of capital
- can be implemented in practice
- are commonly used in practice.

Each model has strengths and weaknesses, which are addressed in more detail in the accompanying SFG reports.

SFG's analysis demonstrates that:

- estimates produced by the other models provide evidence that sole reliance on the SL CAPM as a starting point will result in a return on equity estimate that is too low to satisfy the requirements of clause 6.5.2 of the NER and the allowed rate of return objective, having regard to current market conditions
- in any case, while each model has its strengths and weaknesses, these other models are relevant to informing the best possible estimate of the return on equity and therefore should be given more weight. Applying them in this way better satisfies the requirements of the NER and is also more consistent with the intent of the AEMC's rule changes.

A departure from the AER's Rate of Return Guideline is necessary as, when practically applied, it effectively assigns little weight to these other models and evidence even allowing for the reasonableness tests within the Guideline.¹⁴³ SFG recommends a weighted average of the estimates produced by each model, where the weights reflect the strengths, weaknesses and relevance of each model. The weights applied are:

- 25% weight to the Dividend Discount Model and 75% to the other three models
- of the 75% weight applied to the other three models, half is applied to the Fama-French Model (37.5%) and half to the CAPM (37.5%)
- the key difference between the two CAPM models (the Black and SL CAPM) is the intercept. The Black CAPM uses an empirical estimate, selected to provide the best fit to the observed data, while the SL CAPM's risk-free rate assumption sets a theoretical lower bound (given a return could not be below this). Twice as much weight is therefore placed on the Black CAPM.

It is noted that this result is relatively insensitive to the choice of weights.

¹⁴³ AER (2013c), *Better Regulation, Rate of Return Guideline*, December 2013, p23.

SFG also shows how the AER's Foundation Model would need to be applied by giving appropriate regard to this other evidence in order to produce a result that meets the requirements of the NER. Not surprisingly, this produces the same return on equity estimate as the multi-model approach because this reflects the best available estimate of the return on equity that satisfies the NER's requirements, in the current market environment.

As highlighted by SFG:

“Indeed, the foundation model approach can only produce a different estimate of the required return on equity if it is implemented in such a way as to either (a) omit evidence that would otherwise have been considered, or (b) change the relative weights that would otherwise have been applied to some evidence.”¹⁴⁴

Ergon Energy has therefore departed from the AER's Rate of Return Guideline and applied SFG's multi-model approach to estimate our proposed return on equity. The next section summarises how the models have been estimated. Should the AER reject our proposed departure, an alternative approach, which would be consistent with the Foundation Model preferred by the AER, is outlined in Section 3.5.

3.2 Estimation of the relevant models

Sharpe-Linter and Black CAPM

Risk free rate

Approach under the AER's Rate of Return Guideline

Under the SL CAPM, the risk free rate should reflect the return on a riskless asset. The most common proxy that has been used is the return on long term sovereign Government bonds. In the Rate of Return Guideline, the AER has proposed to:

- use the yield on 10 year Commonwealth Government bonds as a proxy for the risk free rate of return
- adopt an averaging period of 20 business days for the purposes of measuring the risk free rate. The sampling window will be as close as practicably possible to the commencement of the regulatory control period.

Ergon Energy's proposal

Ergon Energy has adopted this approach. The risk free rate utilised by SFG in its Addendum to the Cost of Equity report¹⁴⁵ was averaged over the 20 business days to 11 July 2014, resulting in an estimate of 3.63%. The current estimate will need to be updated for the AER's Final Distribution Determination. In order to be consistent with the NER, any material changes in prevailing market conditions at the time the risk free rate is observed would also necessitate a review of the MRP.

¹⁴⁴ SFG Cost of Equity Report, p96.

¹⁴⁵ Refer to 08.01.02 – SFG Consulting: Updated estimate of the required return on equity.

Zero beta premium (Black CAPM)

Approach under the AER's Rate of Return Guideline

While the AER has referenced the Black CAPM in determining where it will select the point estimate for beta from within its recommended range, it does not address the estimation of the zero beta premium.

Ergon Energy's proposal

SFG's report, *Cost of Equity in the Black Capital Asset Pricing Model*,¹⁴⁶ contains more detail as to how the return on equity has been estimated using this model. As noted previously, the key difference between the SL CAPM and the Black CAPM is the intercept. In the case of the Black CAPM, this is the zero beta return, which represents the risk-free rate plus the zero beta premium.

SFG uses twenty years of returns (from 1994 to 2013) to estimate the zero beta premium. SFG's estimation technique relies solely on stock returns, government bond yields, market capitalisation, book-to-market ratios and industry classifications. The resulting estimate is 3.34%.

Market risk premium

Approach under the AER's Rate of Return Guideline

The MRP is the expected return over the risk-free rate that investors would require in order to invest in a well-diversified portfolio of risky assets. The MRP represents the risk premium that investors who invest in such a portfolio can expect to earn for bearing only non-diversifiable risk.

The Rate of Return Guideline does not specify a preferred value for the MRP but indicates that the AER will adopt a 10 year forward looking MRP and consider a broad range of evidence in arriving at its estimate, including historical excess returns, dividend growth model, survey evidence, implied volatility and recent determinations among Australian regulators. Based on the available evidence, the AER will determine a range and a point estimate for the MRP.

Ergon Energy has a number of concerns with the AER's approach. These are outlined in more detail in Chapter 3 of the SFG Cost of Equity Report.¹⁴⁷ A summary of these concerns include:

- 1 The AER's reliance on both arithmetic and geometric means of historical excess returns. The concern with the use of geometric means is that this assumes that historical data will repeat in the same sequence in the future. It is also noted that most other Australian regulators rely on arithmetic means only. SFG therefore considers that only the arithmetic mean should be used.
- 2 The AER has not adopted NERA's proposed adjustment to the Brailsford et al data, which addresses a downward systematic bias in that data. SFG considers that this adjustment should be made.
- 3 The AER's historical excess return dataset in the materials supporting its Guideline is limited to post 1958, and only goes to 2012. SFG proposes that the entire dataset should be used (including pre-1958) and be updated to include 2013.
- 4 Given an analysis of historical excess returns will reflect 'average' market conditions over that timeframe, consideration should be given as to what extent prevailing market

¹⁴⁶ 08.01.05 – SFG Consulting: *Cost of Equity in the Black Capital Asset Pricing Model*.

¹⁴⁷ 08.01.01 – SFG Consulting: *The Required Return on Equity for Regulated Gas and Electricity Network Businesses*, p41.

conditions reflect these average conditions. This is not currently contemplated in the AER's approach.

- 5 While the Ibbotson approach informs the MRP range, the Wright approach, which has been acknowledged as relevant by the AER, is only proposed to be used to assess the overall return on equity. This relevant piece of evidence could therefore have limited, if any, practical influence on the return on equity outcome. This is not considered to meet the requirements of the NER.
- 6 SFG considers that the AER's application of the Dividend Discount Model, including the downward adjustment to the growth factor, will not produce the best estimate of expected returns. Instead, it recommends its own approach, which avoids the need to impose a growth rate assumption by simultaneously estimating it.
- 7 SFG discounts the use of survey evidence, which the AER proposes to rely upon in its Rate of Return Guideline. This is because none of the surveys that the AER proposes to rely upon satisfy the criteria set out by the Tribunal in assessing an appeal made by Envestra.¹⁴⁸ If this evidence is to be relied upon, the estimates need to be adjusted to reflect the assumed value of gamma.
- 8 While the AER has acknowledged that independent expert reports are relevant, like the Wright approach, they are only proposed to be used to assess the overall return on equity. Again, this relevant piece of evidence could therefore have limited, if any, practical influence on the return on equity outcome and is therefore not considered to meet the requirements of the NER.

Having regard to the above considerations, Ergon Energy is of the view that the AER's approach to estimating the MRP will not produce the best possible estimate in the current market, having regard to the requirements of the NER. This necessitates a departure from the AER's Rate of Return Guideline in terms of the approach that is used to estimate the MRP.

Ergon Energy's proposal

Ergon Energy proposes to depart from the AER's Rate of Return Guideline to estimate the MRP and is relying on the analysis conducted by SFG in its Cost of Equity Report. Again, this involves making appropriate use of all relevant models and evidence, including elevating the status of the Wright approach and independent expert evaluation reports, which while accepted as relevant by the AER, risk having no practical influence on the return on equity outcome under its approach. Each model and data source has its relative strengths and weaknesses and SFG has weighted each approach based on these.

Ergon Energy's addendum to the SFG report includes estimates as at 11 July 2014.¹⁴⁹ Table 54 shows the resulting weighted average MRP estimate.

¹⁴⁸ Application by Envestra Ltd (No 2), ACompT 3.

¹⁴⁹ 08.01.02 – SFG Consulting: Updated estimate of the required return on equity, p3.

Table 54: Market risk premium estimate

Method	Weighting	MRP	Required return on the market
Historical returns	20%	6.63%	10.26%
Wright approach	20%	8.08%	11.71%
Dividend discount model	50%	7.79%	11.42%
Independent expert valuation reports	10%	7.03%	10.66%
Weighted average		7.57%	11.20%

SFG also shows that the estimate is relatively insensitive to the weights applied, changing by less than 10 basis points if:

- each of the above methods are equally weighted (i.e. 25%)
- equal weight is applied to the Ibbotson historical returns and Wright approach only
- equal weight is applied to the Ibbotson historical returns, Wright and Dividend Discount Model approaches.

The above estimate assumes a theta of 0.35. If a theta of 0.7 is assumed, the MRP needs to be adjusted for that assumption.

Ergon Energy considers that the thorough and robust approach employed by SFG to estimate the MRP produces the best available estimate that satisfies the requirements of the NER, having regard to prevailing conditions in the market for funds. If there is a material change in market conditions between now and the Final Distribution Determination, the MRP will need to be reviewed and possibly amended consistent with the approach outlined by SFG.

Equity beta

Approach under the AER's Rate of Return Guideline

The AER's Rate of Return Guideline proposes an equity beta of 0.7. SFG has critiqued the approach applied by the AER to arrive at its preferred equity beta estimate and has identified concerns with:

- the AER's conceptual analysis of beta
- the AER's reference to the betas of water utilities, which are not considered relevant to the estimation of beta for the efficient benchmark entity
- the AER's reliance on a small sample of domestic energy network businesses for its empirical analysis
- the limited weight that the AER has placed on some of the relevant evidence to inform its equity beta estimate, for example, relegating the role of the Black CAPM to influence the decision as to where the point estimate should be selected from within the range.

The AER's equity beta of 0.7, which is at the upper bound of its preferred range, most likely underestimates the systematic risk of the efficient benchmark entity. This in turn will result in the return on equity being underestimated, which will fail to satisfy the requirements of the NER.

Ergon Energy's proposal

Ergon Energy is proposing to depart from the AER's Rate of Return Guideline to estimate the equity beta. We are relying on the analysis conducted by SFG in its Cost of Equity Report, which shows that an equity beta of 0.7 underestimates the systematic risk of the efficient benchmark entity.

SFG highlights the unreliability of the AER's small sample of domestic firms and uses a wider sample that includes 56 relevant international firms that are primarily engaged in regulated transmission and distribution activities. This arrives at an equity beta of 0.82.

Ergon Energy therefore proposes to apply SFG's equity beta estimate of 0.82 in the SL and Black CAPM, because this is considered to be the best available estimate that satisfies the requirements of the NER, having regard to prevailing conditions in the market for funds.

Summary: Sharpe-Lintner CAPM estimate

Combining the above parameters, the SL CAPM estimate is as follows:

$$\begin{aligned}\text{Required return on equity} &= \text{Risk free rate} + \text{Equity beta} * \{\text{Required return on the market} - \text{risk free rate}\} \\ &= 3.63\% + 0.82 * \{11.2\% - 3.63\%\} \\ &= 3.63\% + 0.82 * 7.57\% \\ &= 9.82\%\end{aligned}$$

Summary: Black CAPM estimate

The approach that has been used to estimate the required return on equity using the Black CAPM is detailed in the accompanying report by SFG.¹⁵⁰ As noted previously, the key difference between the SL CAPM and the Black CAPM is the zero beta premium. Otherwise, it uses the same equity beta (0.82) and required return on the market (11.2%).

The required return on equity under the Black CAPM is specified as:

$$\begin{aligned}\text{Required return on equity} &= \{\text{Risk free rate} + \text{zero beta premium}\} + \text{Equity Beta} * \{\text{Required return on the market} - (\text{Risk free rate} + \text{zero beta premium})\} \\ &= \{3.63\% + 3.34\%\} + 0.82 * \{11.2\% - (3.63\% + 3.34\%)\} \\ &= 10.43\%\end{aligned}$$

Fama-French model

The approach that has been used to estimate the required return on equity using the Fama French Model is detailed in the accompanying report by SFG.¹⁵¹

¹⁵⁰ 08.01.05 – SFG Consulting: Cost of Equity in the Black Capital Asset Pricing Model.

¹⁵¹ 08.01.06 – SFG Consulting: The Fama French model.

The first step in the process is to consider the return on equity without imputation credits (given the risk premiums for the additional market factors do not include any compensation for imputation credits). As noted above, SFG's with-imputation return on the market estimate is 11.2%, which equates to an ex-imputation required return of 10.12%.

In estimating the compensation for the market, firm size and book to market risk factors, SFG has placed 24% weight on Australian firms and 76% on US-listed firms.¹⁵² SFG used monthly data from January 1985 to February 2014. The factors estimated are:

- market exposure: $0.77 * (10.12 - 3.63)$
- size: -0.19%
- book to market: 1.15%.

Applying the risk free rate of 3.63%, this results in an ex-imputation return on equity of 9.63%, which equates to a with-imputation return of 10.66%.

Dividend Discount Model

The approach that has been used to estimate the required return on equity using the Dividend Discount Model is detailed in the accompanying report by SFG.¹⁵³ This approach, which was recently published in the *Review of Accounting Studies*,¹⁵⁴ includes a number of methodological enhancements that are designed to address estimation error, some of which address issues previously raised by the AER. For example, one of the particular concerns expressed regarding the use of Dividend Discount Models is the forward-looking growth assumption. SFG has addressed this by jointly estimating the return on equity and long-term growth.

In Ergon Energy's view, SFG's rigorous approach results in the best possible estimate of the return on equity applying the Dividend Discount Model. For the reasons outlined above, this estimate should be considered along with the estimates produced by the other three models in informing the required return on equity that satisfies the requirements of the NER. Confining its role to informing the MRP only (and then only alongside other approaches), as the AER has done, gives insufficient weight to this relevant model.

SFG's estimate of the return on equity using the Dividend Discount Model is 10.77%.

3.3 Other considerations – Consumer Challenge Panel

In our meeting with Consumer Challenge Panel (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 (OFGEM)
- what expected returns on equity are received by some of our customer groups.

¹⁵² Having regard to the composition of the sample, which comprised nine Australian stocks and 56 US stocks, this gives double the weight of Australian stocks to US stocks.

¹⁵³ 08.01.07 – SFG Consulting: *Alternative Versions of the Dividend Discount Model and the Implied Cost of Equity*.

¹⁵⁴ Fitzgerald, Gray, Hall & Jeyaraj (2013), Unconstrained Estimates of the Equity Risk Premium, *Review of Accounting Studies*, 18:560-639.

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 consumers and their report forms part of our Regulatory Proposal.¹⁵⁵

The Synergies report does indicate that the issues raised by the CCP and consumers 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 Guidelines 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 last 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

Applying the weights to each model as specified above, Ergon Energy's proposed return on equity is 10.53%,¹⁵⁶ as shown in Table 55.

Table 55: Ergon Energy's proposed return on equity

Model	Weighting	Return on equity
Sharpe-Lintner CAPM	12.50%	9.82%
Black CAPM	25.00%	10.43%
Fama-French	37.50%	10.66%
Dividend Discount Model	25.00%	10.77%
Weighted average		10.53%

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.

3.5 Alternative approach if multi-model proposal departure from Foundation Model is rejected by the AER

If the AER rejects Ergon Energy's proposed departure from its Rate of Return Guideline in favour of its Foundation Model approach, Ergon Energy does not consider that the estimation of the SL CAPM based on the AER's Rate of Return Guideline will produce an estimate that satisfies the requirements of the NER. As noted above, SFG has shown that the SL CAPM estimate is clearly

¹⁵⁵ Refer to 08.01.04 – Synergies Economic Consulting: Response to Issues Raised by Consumer Challenge Panel.

¹⁵⁶ The calculated WACC is based on a rounded estimate of 10.5%, as per the PTRM.

an outlier compared to the other three models (and as evident from Table 55 above, remains well below the other three estimates even when the model is re-specified based on SFG's recommendations).

Ergon Energy therefore submits that if the AER is to 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,¹⁵⁷ involves using all relevant models and evidence to estimate the parameters in the SL CAPM. This involves applying:

- the same risk-free rate as specified above (3.63%), which is consistent with the AER's Rate of Return Guideline
- the same MRP estimate as proposed above (7.57%), which departs from the AER's Rate of Return Guideline by using all relevant models and evidence to estimate the MRP
- an equity beta of 0.91, which is different from SFG's empirical estimate of beta if it is applied in the SL CAPM as part of Ergon Energy's proposed multi-model approach. This revised estimate of 0.91 has been informed by the SL CAPM, Black CAPM, Fama French and Dividend Discount Model. It is necessary to replace SFG's empirical beta estimate with this multi-model estimate if the AER rejects the application of all four models as foundation models.

It is not surprising that this re-specified SL CAPM arrives at the same estimate as would result from the application of Ergon Energy's proposed multi-model approach, which is 10.53%. This is because this is the estimate that satisfies the requirements of the NER, including the allowed rate of return objective, having regard to prevailing conditions in the market for funds.

4 Rate of return on debt

Ergon Energy has proposed a return on debt of 6.36% for the first year of the next regulatory control period. It is acknowledged that this will be updated prior to the Final Distribution Determination. The return on debt for the subsequent years of the regulatory control period will be updated annually under the trailing average approach.

Like the return on equity, the return on debt must also be estimated so that it contributes to the allowed rate of return objective.¹⁵⁸ 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).¹⁵⁹ The NER provides a choice of three methodologies for estimating the return on debt being:

- an 'on the day' approach, which reflects 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
- a trailing average portfolio approach, which reflects 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
- a combination of the above two methodologies.

¹⁵⁷ 08.01.01 – SFG Consulting: *The Required Return on Equity for Regulated Gas and Electricity Network Businesses*, p92.

¹⁵⁸ NER, clause 6.5.2(h).

¹⁵⁹ NER, clause 6.5.2(i).

4.1 Approach under the AER's Rate of Return Guideline

The AER has proposed to adopt the trailing average portfolio approach to estimate the return on debt. Under this approach:

- the return on debt will be updated each year of the regulatory control period
- a ten year benchmark term will be adopted, based on an assumed BBB+ credit rating
- equal weights will be applied to all elements of the trailing average.

The return on debt would be measured using an averaging period of ten or more consecutive business days and no more than twelve months. The business is required to nominate its averaging periods for each year of the regulatory control period in its Regulatory Proposal.

Specifically, the allowed return on debt for each regulatory year within a regulatory control period would be determined in accordance with the following formula:

$${}_xkd_{x+1} = \frac{1}{10} \cdot \sum_{t=1}^{10} {}_{x-10+t}R_{x+t}$$

where:

- ${}_xkd_{x+1}$ refers to the allowed return on debt for the regulatory year x+1
- ${}_{x-10+t}R_{x+t}$ refers to the estimated prevailing rate of return on debt that was entered into in year (x-10+t) and matures in year (x+t) (in the formula above all debt has a ten year term)
- weights of 1/10 will apply to each element of the trailing average.

Estimates of ${}_{x-10+t}R_{x+t}$ represent simple averages of the estimates for each business day within the averaging period corresponding to year (x-10+t).

The AER intends to transition NSPs from the current 'on the day' approach to the trailing average portfolio approach over a period of ten years. As a consequence of this approach, in the first regulatory year of the transitional period the allowed return on debt would 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%.

In terms of the data source used to estimate the return on debt, the AER's Rate of Return Guideline proposes the use of published yields from an independent third party data provider. While Bloomberg's fair value curves¹⁶⁰ have been the primary source of data relied upon recently, there have been some concerns raised with this approach, such as the maximum term to maturity currently remaining at seven years and issues with the transparency of its methodology.

The RBA has recently begun publishing its own data series for non-financial corporates rated A and BBB, which includes estimates out to ten year terms. Currently, this data is only published for the last trading day in each month, although it is understood that the RBA intends to commence publishing daily data at some point in the future.

In April 2014, the AER published an Issues Paper on the choice and use of third party data provider, which recognises that the RBA data is now available in addition, or as an alternative, to

¹⁶⁰ It is also noted that Bloomberg will cease publishing its fair value curves in favour of its BVAL curves.

Bloomberg's data series.¹⁶¹ This also raises issues such as the current frequency of publication by the RBA (which is not technically compliant with its Rate of Return Guideline), as well as whether the return on debt using the RBA data should be estimated based on total yields, the spread to Commonwealth Government bond rates or the spread to the bank bill swap rate. Ergon Energy notes that the RBA data has already been employed by the AER in its recent Transitional Determinations (where a three month average of the month-end data was used).¹⁶²

The AER has indicated that it is not intending to select one series over another. This decision will be made at the time of each regulatory determination. It will therefore not be publishing a specific decision on this matter. It will first be considered in its determinations for the NSW and ACT electricity distribution networks and the NSW, ACT and Tasmanian electricity transmission networks.

4.2 Ergon Energy's proposed approach

Ergon Energy proposes to comply with the AER's Rate of Return Guideline in relation to the estimation of the return on debt in 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.

Ergon Energy proposes to depart from the AER's Rate of Return Guideline in the following areas because it does not consider that the AER's approach will result in the best possible return on debt estimate having regard to the requirements of the NER:

- the notional credit rating assumption: Ergon Energy is proposing that this should be BBB
- the weighting approach: Ergon Energy is proposing that this should be a weighted average, based on changes in the PTRM debt balances.

The reasons for these departures are provided below, along with the approach that Ergon Energy has used to estimate the return on debt, including:

- the nomination of future averaging periods
- the data source used to estimate the return on debt
- the process that will be applied to estimate the return on debt each year.

Notional credit rating assumption

Issues with the AER's approach

In assessing the notional credit rating assumption under its Rate of Return Guideline, the AER relied upon a historical analysis of the credit ratings maintained by a sample of energy network businesses over the period 2002 to 2013. It arrives at a median of BBB+ (negative watch) over this period.

¹⁶¹ AER (2014b), *Return on Debt: Choice of Third Party Data Service Provider, Issues Paper*, April 2014.

¹⁶² AER (2014c), *Ausgrid, Endeavour Energy, Essential Energy, ActewAGL, Transitional Distribution Determination, 2014-15*, April 2014; and AER (2014d), *Transgrid, Transend, Transitional Transmission Determination, 2014-15*, March 2014.

It also states:

“We also note that there have been some recent credit downgrades. Notwithstanding, our view is that credit ratings are relatively steady for regulated energy businesses over a period of time. Therefore, we consider a historical credit rating analysis produces a more reliable result.”¹⁶³

The AER provides no information or evidence supporting its view, or why this proves that a historical analysis will produce a more reliable result.

Unlike some of the other information sources that inform the rate of return assessment, published credit ratings are truly forward looking. Credit rating information reflects the ratings agency’s current view as to the creditworthiness of an entity. While the opinion might be informed by historical data, the opinion itself is forward looking.

On this basis, it could be argued that the only data that is relevant to the assessment of the notional credit ratings is the current ratings of the sample. However, it is accepted that it is useful to consider this in context of any *recent* trends in each entity’s rating. At maximum, the horizon of any historical analysis should be limited to five years. The credit rating held by a firm back in 2002 is of absolutely no relevance to an assessment of what its credit rating is expected to be in the next five years.

Indeed, Ergon Energy contends that having regard to this older data could actually be misleading and results in error, that is, a notional credit rating assumption that is higher or lower than what the credit rating of the efficient benchmark firm should be, having regard to the level of gearing.

Ergon Energy notes the analysis submitted by Jemena Gas Networks,¹⁶⁴ which presents the credit ratings for each firm in the AER’s sample between 2002 and 2013. This showed that the median credit rating of the sample for each year changed from BBB+/A- in 2007 to BBB in 2009, where it has remained for the duration of the period. The ratings for the last five years are presented in Table 56.

Table 56: Credit ratings of energy network businesses, 2009-2013

Firm	2009	2010	2011	2012	2013
APT Pipelines	BBB	BBB	BBB	BBB	BBB
ATCO Gas	n/a	n/a	BBB	BBB	BBB
DBNGP Trust	BBB-	BBB-	BBB-	BBB-	BBB-
DUET Group	BBB-	BBB-	BBB-	BBB-	BBB-
ElectraNet Pty Ltd	BBB	BBB	BBB	BBB	BBB
Energy Partnership (Gas)	BBB-	BBB-	BBB-	BBB-	BBB-
Envestra Ltd	BBB-	BBB-	BBB-	BBB-	BBB
ETSA Utilities	A-	A-	A-	A-	A-

¹⁶³ AER (2013b), Ibid, p229.

¹⁶⁴ Jemena Gas Networks (NSW) Ltd (2014), *2015-20 Access Arrangement Information, Appendix 9.10, Return on Debt Proposal*, 30 June 2014.

Firm	2009	2010	2011	2012	2013
Powercor Utilities	A-	A-	A-	A-	A-
SP AusNet Group	A-	A-	A-	A-	BBB+
SPI (Australia) Assets	A-	A-	A-	A-	BBB
The CitiPower Trust	A-	A-	A-	A-	A-
United Energy Distribution	n/a	n/a	n/a	n/a	n/a
Median	BBB	BBB	BBB	BBB	BBB

Source: Jemena Gas Networks (NSW) Ltd (2014), *2015-20 Access Arrangement Information, Appendix 9.10, Return on Debt Proposal*, 30 June 2014, p9.

Reference is also made to other evidence:

- 1 The 2013 report from Kanangra Ratings Advisory Services¹⁶⁵ submitted by the Energy Networks Association (ENA) in the context of the AER's review of its Rate of Return Guideline. This analysis supports a rating of no more than BBB and highlights the potential adverse implications of increased discretion by the AER on the perceived financial health of the NSPs it regulates.
- 2 A 2014 report prepared by CEG¹⁶⁶ for the NSW DSNPs, which shows that the median credit rating has been BBB over an even longer time horizon.

It is noted that ratings agencies have previously expressed concerns regarding the outlook for regulated Australian energy network businesses in response to the recent changes to the regulatory framework. For example, Standard and Poor's observed that:

"We believe regulators' greater discretion in determining revenues will have some impact on the predictable, stable, and transparent regulatory practice to date. Consequently, the changes could weaken Standard & Poor's assessment of the sector's regulatory stability and predictability, and ultimately, the credit quality of the rated entities..."

If our assessment of regulatory risk for the sector deteriorates materially, our view of the credit rating of the rated network utilities could change significantly. For example, if an entity with "excellent" BRP is weakened to "strong", it could result in the credit rating being lowered by one or two notches, assuming no steps are taken to strengthen the finances. Also, somewhat higher regulatory risks could mean slightly higher threshold financial metrics for a given rating currently."¹⁶⁷

¹⁶⁵ Refer to http://www.aer.gov.au/sites/default/files/Essential%20Energy%20-%20Attachment%207.6_Kanangra%20-%20Credit%20Ratings%20for%20NSPs%20-%202014.pdf.

¹⁶⁶ Refer to http://www.aer.gov.au/sites/default/files/Essential%20Energy%20-%20Attachment%207.1_WACC%20estimates%20A%20report%20for%20NSW%20DNSPs%20-%202014.pdf.

¹⁶⁷ Standard and Poor's (2012), *Australian Network Utilities: Draft Reforms Give Regulators More Flexibility, but Raise Credit Risks*, 22 October 2012, pp9-10.

Ergon Energy considers that such statements do not support the AER's assessment of BBB+, noting that they were made at a time when the median credit rating was already at BBB.

Ergon Energy's proposal

For the above reasons, Ergon Energy considers that the AER's notional credit rating assumption of BBB+ does not satisfy the NER's requirements, as it is not considered to reflect the creditworthiness of the efficient benchmark firm. This is of no direct consequence in terms of Ergon Energy's return on debt estimate because the AER (and other Australian regulators) have estimated it for BBB+ rated firms with reference to the broader BBB sample (comprising BBB-, BBB and BBB+). This in turn recognises the lack of liquidity in the Australian corporate bond market, particularly for lower investment grade credits for longer terms (in other words, the sample for BBB+ or BBB only would be too small, which increases the risk of estimation error).

Notwithstanding this, Ergon Energy is proposing to depart from the AER's Rate of Return Guideline on this point and has assumed a notional credit rating of BBB. This is considered to be a more reliable forward-looking estimate of the notional credit rating of the efficient benchmark firm over the next regulatory control period.

Weighting approach

Issues with the AER's approach

The AER proposes to apply a simple weighted average approach to update the return on debt in each year. Ergon Energy's concern with this is that it does not recognise the inherently lumpy nature of network investment, which will similarly be reflected in uneven borrowing profiles across the regulatory control period.

One of the reasons put forward by the AER for this is that it would necessitate different definitions of the efficient benchmark firm in recognition of the different capital expenditure profiles and borrowing requirements.¹⁶⁸ Ergon Energy does not agree that this is necessary and questions why a separate efficient benchmark firm definition is necessary simply because a firm has a different borrowing profile from another.

The key issue is whether or not the decision to invest is consistent with efficient practice, which is considered by the AER in approving the projected capital expenditure program. The onus is on the NSP to show that its capital expenditure program is efficient given factors such as the age and condition of its network assets and expected future demand growth. If this is not the case, it will not be approved by the AER.

The approved capital expenditure and associated borrowing profile is contained in the approved PTRM. Ergon Energy is proposing that instead of applying equal weights, the weighting approach be based on the debt component of the forecast capital expenditure approved in the PTRM. This is a simple and transparent approach, cannot be gamed and is consistent with what an efficient benchmark firm would be expected to do.

It is quite possible that actual borrowings will differ from the approved forecast. It is considered acceptable for this risk to be borne by the NSP. In contrast, the use of a simple average creates a certain mismatch unless expected borrowings are nil (or very small). Apart from ensuring a known

¹⁶⁸ AER (2013b), *Ibid.*

mismatch between the NSP's regulated and actual cost of debt, this is also inconsistent with the NER requirement that regard must be given to:

“...the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity referred to in the *allowed rate of return objective*...”¹⁶⁹

“...the incentives that the return on debt may provide in relation to capital expenditure over the *regulatory control period*, including as to the timing of any capital expenditure...”¹⁷⁰

Achieving a better alignment between the return on debt that would apply to new capital expenditure and prevailing market rates provides a clearer investment signal. A significant mismatch between the regulated return on debt and the costs that a NSP would face in undertaking new borrowings is more likely to distort investment decisions.

Ergon Energy's proposal

For the above reasons, Ergon Energy considers it necessary to depart from the weighting approach specified in the AER's Rate of Return Guideline. We consider that a PTRM-based weighting approach better satisfies the requirements of the NER because it will reduce the difference between the actual and benchmark return on debt, as per clause 6.5.2(k)(1) of the NER. It is a clear, transparent approach that can be easily implemented and reflects the practices of a benchmark efficient NSP.

The way that it would be implemented by Ergon Energy is discussed further below.

Nomination of future averaging periods

Issues with the AER's approach

As noted above, while not required under the NER, the AER requires NSPs to nominate their proposed averaging periods for each year of the regulatory control period in the Regulatory Proposal.

Practically, given that most NSPs can be expected to at least start from the position of minimising the difference between their actual cost of debt and the regulated benchmark cost of debt (as recognised by clause 6.5.2(k)(1) of the NER), this requires them to identify the timeframe over which they intend to refinance existing debt, as well as raise new borrowings to fund capital expenditure, in each of the next five years. This is very difficult to do with any certainty now.

The amount and timing of future borrowing requirements is difficult to predict well in advance. This will be a function of a number of factors, including project timeframes, project costs and capital market conditions. Ergon Energy faces the additional uncertainty of possibly being required to raise funds in the private market at some point in the future, which could be within the next five years.

¹⁶⁹ NER, clause 6.5.2(k)(1).

¹⁷⁰ NER, clause 6.5.2(k)(3).

An additional source of uncertainty is the pricing rule change proposal that is currently being considered by the AEMC.¹⁷¹ This will determine the process and timing of annual price reviews. This will therefore also directly influence the end date of NSPs' proposed averaging periods, noting that the AER's Rate of Return Guideline provides that the averaging period "should be as close as practical to the commencement of each regulatory year in a regulatory control period".¹⁷² The AEMC's Final Determination on this rule change proposal is not due until late November 2014, which is after the date of lodgement of this Regulatory Proposal. Ergon Energy has therefore had to nominate proposed averaging periods based on the Draft Determination, noting that the final process and/or timeframes for the annual price reviews may end up being different.

Ergon Energy's proposal

Ergon Energy's Regulatory Proposal includes a "placeholder" averaging period for the first year of the regulatory period, being 2015-16, based on a mid-point observation between a one month and 12 month averaging period, consistent with or close to what the AER's Rate of Return Guideline considers is within the lower and upper bound for a market observation period.

Ergon Energy submitted our proposed averaging period for the cost of debt in 2015-16 as part of our Framework and Approach submission. We understand the AER's preliminary view is that our proposed averaging period was consistent with conditions outlined in the Rate of Return Guideline, but the AER will make a formal decision in its Final Distribution Determination.

While as outlined above, 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 next regulatory control period are included as part of this Regulatory Proposal.¹⁷³ As noted above, 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 the remaining four years of the regulatory control period as a placeholder.

Data source

Ergon Energy's proposal

For the purpose of calculating the return on debt for the first year of the regulatory control period, Ergon Energy has used the RBA's BBB data series, because:

- the RBA is a reputable and independent data provider
- it currently publishes BBB estimates for the longest term to maturity (which has recently been between eight and nine years)
- the data is readily accessible by all stakeholders
- the methodology it used is transparent (although its underlying sample of bonds is not known).¹⁷⁴

¹⁷¹ AEMC (2014). Ibid.

¹⁷² AER (2013c), Ibid, p29.

¹⁷³ Refer to Ergon Energy's supporting document *08.02.04 – Proposed Averaging Period for the Cost of Debt*.

¹⁷⁴ It is better suited to automatic updating of the return on debt estimate when applying the trailing average approach.

There are two issues with the use of the RBA data that Ergon Energy has sought to address in this proposal. First, the RBA publishes the average tenor of the sample of bonds underpinning the estimate for each maturity (which it terms the 'effective tenor'). For the ten year estimate, this has been less than ten years. For example, in July 2014 the effective tenor of the ten year estimate was 8.64 years. This means that the RBA's ten year estimate is really an 8.64 year estimate.

Accordingly, consistent with the approach that has been taken in applying Bloomberg data, it is necessary to extrapolate this estimate to obtain an exact ten year estimate. This is based on a methodology produced by the Queensland Treasury Corporation (QTC).¹⁷⁵ QTC presents two alternative extrapolation approaches, one of which only uses the seven and ten year estimates (Method 1) and an alternative that uses all of the spread and tenor estimates provided by the RBA, that is, its published three, five, seven and ten year estimates (Method 2).

QTC considers that Method 2 produces more robust estimates that are less volatile than Method 1. Ergon Energy has therefore applied Method 2. Otherwise, this is consistent with the way in which the AER has applied its paired bonds extrapolation (which only uses two data points).

The second issue with the RBA data is that it currently only publishes estimates as at the last day of each month, which is technically not compliant with the AER's Rate of Return Guideline. Ergon Energy has addressed this issue by interpolating daily estimates using the RBA's month-end observations.

The NER no longer requires the return on debt and equity to be calculated using the same base interest rate (being the risk free rate). Ergon Energy has therefore chosen to use the RBA's margins to the swap rate, which are then added to the daily ten year swap rate to produce daily estimates of the benchmark debt yield. This approach reflects how corporate debt is actually priced and traded in the market. Ergon Energy considers this to be more consistent with the efficient benchmark firm approach and therefore more consistent with the requirements of the NER.

The process that Ergon Energy proposes to apply to estimate the return on debt each year is summarised in the next section.

Alternative approach if Ergon Energy's proposed use of the RBA data is rejected

If the AER rejects Ergon Energy's proposal to use the RBA data and instead proposes to continue to use Bloomberg data to estimate the return on debt (either on its own or in combination with the RBA data), Ergon Energy has concerns with the use of the paired bonds approach that has most recently been used by the AER to extrapolate Bloomberg's seven year BBB yield. In particular, it typically relies on a very small sample, sometimes including firms in the A rating category. This means the estimate is more likely to be influenced by the idiosyncratic features of the bonds or firms in that small sample. Where A rated bonds are used, there is a risk that the increment for an issue in the A category is not sufficiently indicative of the increment for BBB. This increases the risk that the resulting estimate does not satisfy the requirements of the NER.

QTC has developed a preferred method based on its quarterly survey of financial market practitioners, which has been independently endorsed as producing the best estimate of the change in the debt risk premium between seven and ten years.¹⁷⁶ Ergon Energy considers that this methodology would better satisfy the requirements of the NER by producing a more robust and

¹⁷⁵ Refer to 08.01.11 – QTC: *Extrapolating the RBA BBB curve to a 10-year tenor*.

¹⁷⁶ Incenta Economic Consulting (2014), *Methodology for Extrapolating the Debt Risk Premium, Report for Jemena Gas Networks and SA Power Networks*, June 2014.

informed estimate of the ten year BBB yield in the current market. If the AER chooses to use Bloomberg data, Ergon Energy therefore proposes that this approach is used for this purpose, as it will produce a more robust estimate of the ten year BBB yield than the paired bond approach and will satisfy the requirements of the NER. It can also be applied formulaically. QTC's methodology is attached to this Regulatory Proposal.¹⁷⁷

Summary of the methodology applied to estimate the proposed return on debt

The following summarises the approach that Ergon Energy has applied to estimate the return on debt. This is the approach that Ergon Energy proposes to apply each year of the regulatory control period as part of the annual update.

Step 1: collect RBA BBB spreads and tenors

Data is accessed from the spreadsheet *F3 Aggregate Measures of Australian Corporate Bond Spreads and Yields: Non-financial Corporate (NFC) Bonds*, available on the RBA's website.¹⁷⁸ The information that is collected for the relevant months is:

- the spread to swap for the 3, 5, 7 and 10 year BBB rated securities
- the effective tenor of the 3, 5, 7 and 10 year BBB estimates.

Step 2: interpolate RBA month-end estimates to produce daily estimates

Until the RBA commences publishing daily estimates, its month-end estimates can be interpolated to produce daily estimates. This is done by taking the difference between the month-end estimates and dividing this by the number of business days for which observations are reported in that month.¹⁷⁹

Step 3: extrapolate RBA estimates to produce true 10 year estimates

Ergon Energy has applied the extrapolation methodology proposed by QTC in the accompanying paper, *Extrapolating the RBA BBB curve to a 10-year tenor*.¹⁸⁰ Method 2 has been adopted, as recommended by QTC. This involves the following steps:

- 1 Estimate the slope of the RBA's BBB swap spread curve using its swap spreads and target tenors for 3, 5, 7 and 10 years. This is done by using the SLOPE function in Excel, which estimates the average slope per year of the relevant curve:

$$\Delta = \text{SLOPE}(\{S_3 S_5 S_7 S_{10}\}, \{ET_3 ET_5 ET_7 ET_{10}\})$$

where:

S_n = RBA BBB swap spread estimate for an n-year target tenor

ET_n = effective tenor of the RBA BBB swap spread estimate for an n-year target tenor

- 2 Estimate the extrapolation margin by multiplying the slope estimated in the first step by the difference between 10 years and the RBA's effective tenor for its 10 year swap spread:

$$EM = \Delta \times (10 - ET_{10})$$

¹⁷⁷ 08.01.10 – QTC: *An alternative extrapolation method to estimate the 10-year BBB+ corporate yield.*

¹⁷⁸ Refer to <http://www.rba.gov.au/statistics/tables/index.html#interest-rates>.

¹⁷⁹ This is shown in 08.01.09 – QTC: *Daily extrapolated RBA yields.*

¹⁸⁰ 08.01.11 – QTC: *Extrapolating the RBA BBB curve to a 10-year tenor.*

where:

EM = extrapolation margin

- 3 Estimate the extrapolated 10 year BBB swap spread by adding the extrapolation margin to the RBA's BBB swap spread for a 10 year target tenor:

$$ES_{10} = S_{10} + EM$$

where:

ES₁₀ = extrapolated 10 year swap spread (semi-annual)

Step 4: collect swap base rate data

This is the end of day 10 year swap rate as published by AFMA. The rate is expressed on a semi-annual compounding basis.

Step 5: calculate 10 year BBB return on debt over relevant averaging period

This involves three steps:

- 1 Calculate the daily 10 year BBB return on debt, which is the sum of the:
 - a) extrapolated ten year swap spread (ES₁₀), as per Step 3, and
 - b) swap base rate, as per Step 4.
- 2 Convert the semi-annual rates to annual effective rates.
- 3 Calculate the average of the daily annual effective rates over the relevant averaging period.

The following additional steps will be required to implement the annual update:

Step 6: calculate weights to be applied in the trailing average return on debt

QTC has recommended a method to calculate the updated trailing average return on debt using the PTRM weights.¹⁸¹ This involves the following steps:

- 1 Calculate the change in the PTRM debt balance in the relevant year, which is based on the difference between the opening and closing balances in the previous regulatory year. That is:

$$\Delta \text{ debt balance}_{t-1} = \text{closing debt balance}_{t-1} - \text{opening debt balance}_{t-1}$$

- 2 Calculate the weight that will be applied to the updated return on debt estimate in that year, or the 'new debt', which is equal to the change in the debt balance in the previous regulatory year, divided by the closing debt balance in that previous regulatory year.

$$\text{weight}_{\text{new debt}} = \Delta \text{ debt balance}_{t-1} / \text{closing debt balance}_{t-1}$$

- 3 Calculate the weight that will be applied to the existing debt in that year, which is equal to:

$$\text{weight}_{\text{existing debt}} = 1 - \text{weight}_{\text{new debt}}$$

Step 7: calculate updated weighted trailing average return on debt

For details of the calculation please refer to *08.01.12 – Weighted Trailing Average Return on Debt Model*.

¹⁸¹ QTC's calculation of this is contained in the spreadsheet provided in *08.01.12 – Weighted Trailing Average Return on Debt Model*.

Step 8: update return on debt estimate in the PTRM

The updated trailing average return on debt is then entered as an input into the PTRM, as proposed for use by the AER for the purpose of the annual price adjustment.

Consistent with the ENA's response to the informal consultation on the amendments to the PTRM that implements the Rate of Return Guideline, Ergon Energy proposes that to reduce volatility in the X-factors that the return on debt for the year of the annual update will change. All remaining years of the regulatory control period will retain the return on debt set out in the Final Distribution Determination until the year in which the return on debt is updated.

4.3 Proposed return on debt

Application of the above approach results in a return on debt estimate of 6.36%, comprising a base swap rate of 4.05% and a debt risk premium of 2.31%. 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.

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.

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

Clause 6.5.3 of the NER requires the income tax building block to be adjusted for the value of imputation credits (gamma). Gamma is estimated as the product of:

- the payout ratio or distribution rate
- the value of imputation credits (theta).

Ergon Energy is proposing a gamma of 0.25, which reflects a distribution rate of 0.7 and theta of 0.35.

6.1 Issues with the AER's approach

The AER's Rate of Return Guideline proposes values for the distribution rate and theta of 0.7 each. Ergon Energy concurs with the AER's distribution rate assumption of 0.7. However, we do not consider that 0.7 is the best value for theta, having regard to the requirements of the NER.

Ergon Energy and other NSPs jointly commissioned a report from SFG Consulting on the value of gamma.¹⁸² The purpose of this analysis was to come up with the best estimate for gamma at the current time, having regard to the requirements of the NER. This also draws upon the Tribunal's findings on gamma as part of the appeal submitted by Ergon Energy, Energex and (now) SA Power Networks.¹⁸³

¹⁸² 08.01.03 – SFG Consulting: An Appropriate Regulatory Estimate of Gamma (SFG Gamma Report).

¹⁸³ Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9.

SFG's Gamma Report identifies a number of issues with the approach taken by the AER in developing its Rate of Return Guideline. It conducts a detailed review of the AER's conceptual interpretation of theta and highlights some fundamental flaws. SFG clearly demonstrates that the relevant task is to establish a market-based value of theta. This also invalidates the equity ownership, tax statistics and 'conceptual goalposts' approach that have been referred to by the AER.

Ergon Energy concurs with this view. The gamma parameter is intended to reflect the value that investors place on franking credits in establishing the rate of return they require from the efficient benchmark firm. This has to be a market value. The AER's conclusion that this should only reflect the extent to which imputation credits might be used to reduce personal tax is erroneous and can (and has) resulted in gamma being overestimated. If the value that investors are assumed to derive from imputation credits is overstated, this will mean that their required rate of return will be underestimated.

SFG has also undertaken an updated empirical analysis of theta using dividend drop-off studies and other market value studies. This analysis concludes that:

- 0.35 remains the best estimate of theta at the current time using a dividend drop-off approach (based on the SFG approach, which has been subject to unprecedented scrutiny)
- other market value studies support an estimate between zero and 0.35.

A value of theta of 0.35 has therefore been recommended by SFG. If anything, the SFG analysis supports the conclusion that a theta of 0.35 is more likely to be at the upper bound of a reasonable range.

Ergon Energy therefore does not consider that the AER's value of theta meets the requirements of the NER. This is primarily because the AER's theta parameter does not reflect the value of theta as assessed from the perspective of investors, who are the providers of capital to the efficient benchmark NSP. In materially overstating the value of theta and hence gamma, the AER is overstating the value that investors place on franking credits, which will result in the return on equity being under-estimated. This will adversely impact on the ability of the business to attract the necessary capital to fund investments, which is contrary to the allowed rate of return objective.

6.2 Ergon Energy's proposal

Based on the advice provided by SFG, Ergon Energy considers that 0.35 is the most appropriate value of theta. A distribution rate of 0.7 and a theta of 0.35 results in a gamma of 0.25. This is the value that Ergon Energy has adopted in this Regulatory Proposal. This is considered the best estimate in the current environment, having regard to the purpose of estimating gamma within the context of the NER and the allowed rate of return objective.

7 Supporting documentation

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

Name	Ref	File name
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
SFG Consulting: Updated estimate of the required return on equity	08.01.02	SFG 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
SFG Consulting: Cost of Equity in the Black Capital Asset Pricing Model	08.01.05	SFG Report Black CAPM
SFG Consulting: The Fama-French Model	08.01.06	SFG Report Fama French
SFG Consulting: Alternative Versions of the Dividend Discount Model and the Implied Cost of Equity	08.01.07	SFG Report Dividend Discount Model
QTC: Daily extrapolated RBA yields	08.01.09	Daily Extrapolated RBA Yields
QTC: An alternative extrapolation method to estimate the 10-year BBB+ corporate yield	08.01.10	QTC Alternative Extrapolation Method Attachment A
QTC: Extrapolating the RBA BBB curve to a 10-year tenor	08.01.11	QTC Extrapolating the RBA Curve
QTC: Weighted Trailing Average Return on Debt Model	08.01.12	Weighted trailing avg return on debt model
Proposed Averaging Period on the Cost of Debt	08.02.04	Proposed Averaging Period for the Cost of Debt

Appendix D: Connection Policy

Introduction

Our Connection Policy sets out the connection services offered by Ergon Energy and how we determine the charges that are payable for those services.

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 next regulatory control period (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 Guidelines¹⁸⁴ 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 – 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.

¹⁸⁴ 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 57: 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. 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, 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 – 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 – 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 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 – 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 – 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 – 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
Ergon Energy Connection Policy	09.01.01	Ergon Energy Connection Policy
Unit Rates for Capital Contributions	09.02.01	Unit Rates for Capital Contributions

Appendix E: Approach to confidential information

Introduction

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.

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 E: 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 *10.01.01 – 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
Confidentiality Template	10.01.01	Confidentiality template

Glossary

ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
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
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNISP	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
ENA	Energy Networks Association
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
GFC	Global Financial Crisis
GST	Goods and Services Tax
IBT	Inclining Block Tariff
ICT	Information and Communication Technologies
Incenta	Incenta Economic Consulting

LED	Light emitting diode
MRP	Market Risk Premium
MSS	Minimum Service Standards
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
NSP	Network Service Provider
NUOS	Network Use of System
OFGEM	Office of Gas and Electricity Markets
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

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