Submission to the AER on its Preliminary Determination

SCS Building Blocks, Control Mechanism and Pricing

Summary

This document sets out Ergon Energy's response to the Australian Energy Regulator (AER) on:

- decisions regarding the Annual Revenue Requirement
- decisions regarding X-factors and control mechanism
- decisions regarding the application of the control mechanism through prices in the regulatory period 2015-20.

Our revised proposal corrects a number of decisions made by the AER in respect of its Preliminary Determination, including:

- changes to the approved equity raising cost for the regulatory control period 2010-15 in 2011-12
- removing the movement in capitalised provisions from the Roll Forward Model
- updating disposal values with those values provided to the AER as part of an information request subsequent to the Regulatory Proposal submission.

Nevertheless, the AER's decision to reduce our total revenue requirements by over 25 per cent was incorrect for a number of reasons.

- There are arithmetic errors in the AER's Preliminary Determination which understated several input values such as forecast capital expenditure and tax allowance.
- The AER rejected Ergon Energy's proposed depreciation schedules on the basis that it creates intergenerational equity issues and substituted a different set of schedules that was no better in eliminating it.
- The AER made adjustments to the Regulatory Asset Base that were outside its powers to do so under the National Electricity Rules.
- Both the rate of return and operating expenditure allowances were set too low and need to be adjusted.

The AER also made several errors in the control mechanism it applied. We request the AER to engage with the material we have already provided and work with Network Service Providers on the proposed amendments to control mechanism arrangements in order to avoid complicated outcomes with customers when setting prices.

Finally, we do not agree with the AER's approach to smoothing revenue requirements or its approach to recovering jurisdictional scheme amounts.

Contents

1. Introduction

On 30 April 2015, the Australian Energy Regulator (AER) released its Preliminary Determination on Ergon Energy's Regulatory Proposal for the regulatory control period commencing on 1 July 2015 and ending on 30 June 2020.

This document details our response to the AER's Preliminary Determination and stakeholder comments in respect to Standard Control Service revenue and price setting (i.e. building blocks, control mechanism and pricing). We have made revisions to our Regulatory Proposal and its supporting documents to reflect these positions, where necessary.

This document is structured in the following manner:

- Chapter 2 summarises the AER's Preliminary Determination in relation to our Annual Revenue Requirement (ARR), including revenue smoothing, revenue increments and the treatment of the shared asset adjustments. It also outlines issues raised by stakeholders in relation to these matters and our response to the positions adopted by the AER and to the concerns raised by stakeholders.
- Chapter 3 summarises the AER's Preliminary Determination in relation to our Regulatory Asset Base (RAB), including the asset base roll forward, capital expenditure and depreciation approach. It also outlines issues raised by stakeholders in relation to these matters and our response to the positions adopted by the AER and to the concerns raised by stakeholders.
- Chapter 4 summarises the AER's Preliminary Determination in relation to regulatory depreciation, including the calculation of remaining asset lives, and outlines our response to the positions adopted by the AER.
- Chapter 5 summarises the AER's Preliminary Determination in relation to corporate income tax, and outlines our response to the positions adopted by the AER.
- Chapter 6 summarises the AER's Preliminary Determination in relation to the control mechanisms applicable to our Standard Control Services and Alternative Control Services, including under and over recovery mechanisms, jurisdictional scheme amounts, side constraints and assignment of retail customers to tariff classes. It also outlines issues raised by stakeholders in relation to these matters and our response to the positions adopted by the AER and to the concerns raised by stakeholders.

1.1. Overview of changes in the Preliminary Determination

The AER proposed a number of changes to our proposed revenues and opening RAB for the regulatory control period 2015-20, some of which have been incorporated in our revised Regulatory Proposal. These changes, and our commentary on each of these changes, are summarised briefly in the Table 1 below.

Table 1: Outcomes of the AER's Preliminary Determination and our response

AER's proposed changes	Our commentary
The AER proposed an opening RAB of $10,102.2 million.	Ergon Energy does not accept this change in the revised proposal. Section 3 of this document sets out our justifications for the revised opening RAB in the revised Regulatory Proposal.
The AER did not include the Hayman Island undersea cable assets in the opening RAB as of 1 July 2015 based on the AER's position not to regulate the services provided by the undersea cable.	Ergon Energy has accepted this change in the revised Regulatory Proposal.
The AER rejected Ergon Energy's remaining lives for assets providing Standard Control Services as of 1 July 2010 and substituted its own remaining lives in the Roll Forward Model (RFM).	Ergon Energy does not accept this change, and instead has used remaining lives as of 1 July 2009 using the average depreciation approach in the revised Regulatory Proposal.
The AER proposed an alternative approach to calculating the remaining asset lives for each asset class as at the end of the regulatory control period 2010-15.	Ergon Energy does not accept this change in the revised proposal. Section 0 of this document sets out our justifications for the revised remaining lives in the revised Regulatory Proposal.
The AER proposed to include the approved equity raising cost for the regulatory control period 2010-15 in 2011-12 rather than 2010-11 as per our October Regulatory Proposal.	Ergon Energy has accepted this change in the revised Regulatory Proposal.
The AER proposed to remove the movement in capitalised provisions from the RFM.	Ergon Energy has accepted this change in the revised Regulatory Proposal.
The AER proposed to replace the actual and estimated disposals set out in our October Regulatory Proposal with updated disposals value provided to the AER as part of an information request subsequent to the Regulatory Proposal submission.	Ergon Energy has accepted this change in the revised Regulatory Proposal.
The AER proposed to amend our proposed Type 5-6 metering adjustment to recognise the AER's remaining life calculation.	Ergon Energy does not accept this change in the revised proposal. Section 3 of this document sets out our justifications for the revised remaining lives in the revised Regulatory Proposal.
The AER proposed to remove other shared assets (i.e. non-meter assets) used in the provision of both Standard Control Services and Alternative Control Services. The proposed revenue adjustment to recognise the shared assets used to provide Alternative Control Services was also removed.	Ergon Energy does not accept this change in the revised proposal. Section 3.4.2 of this document sets out our justification to apply a revenue adjustment to recognise the shared assets used to provide Alternative Control Services.
The AER proposed an operating expenditure base year of 2012-13.	Ergon Energy does not accept this base year and instead proposes that 2013-14 should be the operating expenditure base year. This is covered in more detail in our submission response, *Opex (Base Year) – Response*, and Appendix A of our revised Regulatory Proposal.
The AER decided to treat charges associated with Powerlink and Chumvale as designated pricing proposal charges, as opposed to operating expenditure.	Ergon Energy has accepted this change in the revised Regulatory Proposal. Section 6.6 provides more detail.
The AER used a new version of the Post Tax Revenue Model (PTRM) (Version 3 January 2015) in its Preliminary Determination. This differs to the version of the PTRM Ergon Energy submitted in our October Regulatory Proposal.	Ergon Energy has accepted this change in the revised Regulatory Proposal.
The AER proposed that the Demand Management Innovation Allowance (DMIA) of $1 million nominal per annum be recognised as a revenue adjustment. Ergon Energy included this value as part of our proposed operating expenditure in the October Regulatory Proposal.	Ergon Energy has accepted this change in the revised Regulatory Proposal and has adjusted our proposed operating expenditure accordingly to remove the DMIA.

AER's proposed changes	Our commentary
The AER proposed not to apply the Efficiency Benefit Sharing Scheme (EBSS) in the regulatory control period 2015-20.	Ergon Energy does not accept this decision and instead proposes that the EBSS be applied for the regulatory control period 2015-20, consistent with the AER's Framework and Approach.
The AER proposed to adjust the EBSS carryover amounts from the regulatory control period 2010-15 to remove the movement in provisions.	Ergon Energy has accepted this change in the revised Regulatory Proposal. Please refer to our supporting submission, *Incentive Schemes – Response*, for more details.
The AER proposed a nominal vanilla Weighted Average Cost of Capital (WACC) of 5.85% for each year of the regulatory control period 2015-20 (to be updated annually for the return on debt).	Ergon Energy does not accept this WACC value and proposes a revised WACC value that is lower than that proposed in our October Regulatory Proposal. Please refer to our response to the AER's decision on the rate of return for more details.

2. Annual Revenue Requirement

2.1. Preliminary Determination

2.1.1. Revenue requirements

The AER did not accept our proposed total revenue requirement of $8,228.6 million. Instead, the AER determined a total revenue requirement of $6,012.6 million. This is a reduction of $2,216.1 million or 26.9 per cent.

Table 2 provides the AER's preliminary determination on the ARRs, broken down by each building block component, and the X-factors to apply in the regulatory control period 2015-20.

Table 2: AER's preliminary determination on Ergon Energy's ARRs, 2015-20

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Return on capital	590.8	617.0	640.4	658.9	674.6
Regulatory depreciation	106.7	121.2	137.3	147.2	142.3
Operating expenditure	327.5	342.1	356.4	372.9	389.0
Revenue adjustments	91.9	49.1	66.9	(21.4)	(2.3)
Net tax allowance	36.3	38.8	41.2	44.8	43.1
Annual revenue requirement (unsmoothed)	1,153.1	1,168.2	1,242.3	1,202.3	1,246.7
Annual expected revenue (excl. additionals)	**1,137.7**	**1,096.7**	**1,282.1**	**1,262.2**	**1,242.7**
X-factor	36.63%	6.00%	(14.00%)	4.00%	4.00%
Additional amounts in DUOS	424.3	331.7	104.9	102.1	99.2
Annual expected revenue (smoothed - incl. additionals)	**1,562.0**	**1,428.4**	**1,387.0**	**1,364.3**	**1,341.9**
Annual change in revenue - incl. additionals	(10.8%)	(8.6%)	(2.9%)	(1.6%)	(1.6%)

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 1 – Annual revenue requirement*, April 2015, p7.

2.1.2. Revenue smoothing

Typically, X-factors are only applied to revenue requirements included in the PTRM. This means the smoothing of revenues excludes other adjustments to the ARR undertaken in the annual pricing proposal process (e.g. cost pass through amounts associated with the Solar Bonus Scheme). Since these adjustments are sizable in the regulatory control period 2015-20, the AER took them into account in determining the smoothed revenue path. That is, the total Distribution Use of System (DUOS) revenue, including the other adjustments, will be smoothed overall.

The AER's 'smoothing profile', which incorporates both DUOS charges and the recovery of jurisdictional scheme amounts, differed slightly to the approach proposed by Ergon Energy. This was a departure from the approach we adopted – a smoothing profile which excluded feed-in tariff (FiT) recoveries. We adopted this profile as we wished to monitor commitments for what we charge for the use of the network.

2.1.3. Revenue increments or decrements

Table 3 sets out the revenue increments or decrements arising from the operation of a control mechanism or schemes that applied in the regulatory control period 2010-15.

Table 3: AER's preliminary determination on Ergon Energy's revenue increments/decrements, 2015-20

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
EBSS	35.4	51.3	69.3	(19.2)	0.0
DMIA	1.0	1.1	1.1	1.1	1.1
Closing balance of DUOS unders/overs account as at 30 June 2015	58.6	n/a	n/a	n/a	n/a
Shared assets	(3.1)	(3.2)	(3.3)	(3.4)	(3.5)
Total	**91.9**	**49.1**	**66.9**	**(21.4)**	**(2.3)**

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 1 – Annual revenue requirement*, April 2015, p15.

2.1.4. Shared assets

In our October Regulatory Proposal, Ergon Energy proposed to apply a revenue adjustment to remove the component of shared assets that are used for unregulated services from the total annual revenue. The AER accepted our updated shared asset revenue adjustments.[1]

We also proposed to do the same for assets that provide both Standard Control Services and Alternative Control Services. The AER did not support this proposal and instead removed the value of assets providing Alternative Control Services from the RAB.

2.2. Stakeholder feedback

Rising revenues and electricity prices are a key concern for our customers and other stakeholders. This theme has remained prevalent during consultation on our October Regulatory Proposal, with many stakeholders calling on the AER and Ergon Energy to deliver lower prices in the regulatory control period 2015-20.[2]

We note the Consumer Challenge Panel (CCP) also commented on our proposed revenues at the public forum held in December 2014, stating they are much higher than actual or allowed revenue in the regulatory control period 2010-15.[3]

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[1] Updated shared asset adjustments were provided in February 2015, in response to an information request from the AER.

[2] See, for example, Cotton Australia (2015), *Submission to the AER, Qld Electricity Distribution Regulatory Proposals 2015-16 to 2019-20*, January 2015, p12; QCOSS (2015), *Understanding the long term interests of electricity customers: Submission to the AER's Queensland electricity distribution determination 2015-2020,* 30 January 2015, pp11-14; and Chamber of Commerce and Industry Queensland (2015), *Submission to the AER on Ergon Energy's Regulatory Proposal for the 2015-2020 Revenue Determination*, 30 January 2015, p4.

[3] Bruce Mountain (2014), *Energex and Ergon's 2015-2020 proposal: initial comments*, Presentation at the AER's Public Forum, 9 December 2014, p2.

Comments received on the various building block components are discussed elsewhere in this submission.

2.3. Other influencing factors

The ARR is affected by changes to the underlying building block components. Factors influencing each of these components are discussed in other sections of our submission to the AER.

2.4. Our response

2.4.1. Summary

The AER's decision to reduce our total revenue requirements by over 25 per cent to $6,021.5 million was not correct for the following reasons:

- There are errors in the AER's determination which make some of the inputs lower than they should be.
- The AER overlooked the need to incorporate certain capital expenditure inputs in its revenue models.
- The AER has deferred the depreciation allowance into the following regulatory control period, which in turn increases the value of the RAB.
- The rate of return set by the AER is too low. Proper regard should be given to the National Electricity Rules (NER) when setting the rate of return.
- The AER has substituted a capital expenditure forecast that is too low – even after errors are accounted for.
- The AER has made adjustments to the RAB that are outside its powers to do so under the NER.
- The operating expenditure forecast determined by the AER has been subjectively determined using a single point estimate and has been set too low, with little regard for the realistic expectations of the expenditure required by Ergon Energy to provide services to customers in regional Queensland.

Consequently, we have not revised our October Regulatory Proposal to reflect the AER's Preliminary Determination on the ARRs.

Further, we note the AER has adopted a smoothing profile which accommodates forecast recovery of jurisdictional scheme amounts. We do not see much merit in this approach as the forecast jurisdictional scheme amounts may be volatile. In addition, the recovery of jurisdictional scheme amounts is not relevant to the distribution services we provide. Instead, they represent a pass through of costs, similar to Transmission Use of System (TUOS) prices. Our preference is to smooth prices based on our part of the customer's bill, which is what we originally proposed.

Finally, Ergon Energy has amended our ARRs based on changes we have made to the underlying building block inputs. The basis of these changes is summarised in other chapters of our submission to the AER, and relate to key inputs such as the rate of return.

These changes are reflected in:

- Chapter 3 of the revised Regulatory Proposal
- *03.01.01 – (Revised) Ergon Energy's Building Block Components*
- *03.01.02 – (Revised) Other Revenue Adjustments.*

3. Regulatory Asset Base

3.1. Preliminary Determination

3.1.1. Introduction

Ergon Energy's Building Block Components supporting document outlined the various components in the calculation of the RAB for each year of the regulatory control period 2010-15, including:

- the opening RAB at the start of the regulatory control period 2010-15
- the actual and estimated capital expenditure, capital contributions and disposals during the regulatory control period 2010-15
- the regulatory depreciation during the regulatory control period 2010-15
- the other adjustments made to the RAB during the regulatory control period 2010-15 to recognise departures to the underlying methods in the AER's RFM and Guidelines.

3.1.2. Opening RAB

The AER did not accept our proposed opening RAB value of $10,041.54 million as at 1 July 2015. Instead, the AER substituted its own value of $10,102.2 million. In doing so, the AER:

- applied the remaining asset lives approved in the 2010-15 Distribution Determination
- removed the movement in capitalised provisions from capital expenditure
- adjusted disposals
- adjusted equity raising costs
- rejected the inclusion of the Hayman Island undersea cable in the RAB
- removed from the RAB an estimated value of the proportion of assets that currently provide Alternative Control Services
- adjusted the amount removed from the RAB for meters (based on the reclassification of Default Metering Services).

A summary of the calculations made to derive the opening RAB is shown in Table 4.

Table 4: AER's preliminary determination on Ergon Energy's opening RAB, 2010-15

$m (nominal)	2010-11 Actual	2011-12 Actual	2012-13 Actual	2013-14 Actual	2014-15 Estimate
Opening RAB	7,148.9	7,870.5	8,393.0	9,072.3	9,681.3
Capital expenditure	809.5	748.3	836.5	743.8	885.9
Inflation indexation on opening RAB	238.3	124.7	210.0	265.8	217.8
less straight-line depreciation	326.3	350.5	367.2	400.5	397.2
Closing RAB	**7,870.5**	**8,393.0**	**9,072.3**	**9,681.3**	**10,387.9**
Difference between estimated and actual capital expenditure	-	-	-	-	(132.8)
Return on difference for 2009-10 capital expenditure	-	-	-	-	(78.3)
Closing RAB as at 30 June 2015	-	-	-	-	10,176.8

$m (nominal)	2010-11 Actual	2011-12 Actual	2012-13 Actual	2013-14 Actual	2014-15 Estimate
ACS (metering and other) assets removed	-	-	-	-	(74.6)
Opening RAB as at 1 July 2015	-	-	-	-	**10,102.2**

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 2 – Regulatory asset base*, April 2015, p7.

3.1.3. Rolling forward of RAB 2015-2020

The AER substituted our proposed closing RAB value of $12,867.0 million, with their own value of $11,773.7 million. This reflects its decision to reduce the capital expenditure and regulatory depreciation allowances, as well as the opening RAB value. A summary of the roll forward values determined by the AER is provided in Table 5.

Table 5: AER's preliminary determination on Ergon Energy's forecast RAB, 2015-20

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Opening RAB	10,102.2	10,551.0	10,951.5	11,266.7	11,535.2
Capital expenditure	555.4	521.7	452.5	415.7	380.8
Inflation indexation on opening RAB	257.6	269.0	279.3	287.3	294.1
Less: straight-line depreciation	364.3	390.2	416.6	434.5	436.4
Closing RAB	**10,551.0**	**10,951.5**	**11,266.7**	**11,535.2**	**11,773.7**

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 2 – Regulatory asset base*, April 2015, p7.

3.1.4. Capital expenditure included in the roll forward of the RAB

The RAB for Ergon Energy in the regulatory control period 2010-15 included a value for forecast capital contributions. To avoid Ergon Energy earning revenue from assets we did not fund, the regulatory determination includes a revenue adjustment, which is equal to the value of the capital contribution, in the regulatory year in which the capital contribution is received. Subsequent to the determination, any differences between the forecast capital contributions and actual capital contributions received are accounted for through the annual “unders and overs” process.

Our October Regulatory Proposal also noted a change in regulatory treatment involving gifted and contributed assets. Transitional clauses 11.16.10 of the NER provided for the operation of a capital contributions policy.

As clause 11.16.10 of the NER no longer has any effect upon commencement of the regulatory control period 2010-15, and with the introduction of the National Energy Customer Framework in Queensland from 1 July 2015, Ergon Energy must put in place a connection policy for the regulatory control period 2015-20.

In order to move away from transitional arrangements to the current approach, Ergon Energy proposed the following approach for the recording and treatment of prepaid and “gifted” capital works:

The forecast contributed and gifted asset values from large customer connections for each regulatory year of regulatory control period 2015-20 were developed by asset class. Please refer to our supporting document *07.00.03 – Customer Connection Initiated Capital Works Expenditure Forecast Summary* for further details on how these forecasts were developed.

The forecast contributed and gifted asset values from large customer connections, by asset class, for each regulatory year of the regulatory control period 2015-20 were then added to the Standard Control Services capital expenditure forecasts by asset class for each regulatory year of the regulatory control period 2015-20. These combined values were then entered into the PTRM for Standard Control Services.

The forecast contributed and gifted asset values from large customer connections, by asset class, for each regulatory year of the regulatory control period 2015-20 were also added to the Standard Control Services capital contribution forecasts by asset class for each regulatory year of the regulatory control period 2015-20. These combined values were also entered into the PTRM for Standard Control Services.[4]

We noted in our proposal that forecast contributed and gifted asset values from large customer connections for each regulatory year of regulatory control period 2015-20 are not recovered twice from revenues for Standard Control Services.

Instead, by adding the contributed and gifted assets from large customer connections during the regulatory control period 2015-20 to both the forecast capital expenditure and the forecast capital contributions for each year of the regulatory control period 2015-20, the PTRM removes the contributed and gifted assets from large customer connections in calculating the net capital expenditure in rows 263 to 322 of the Input tab. Only the Standard Control Services net capital expenditure is used to calculate the return on and depreciation allowance for Standard Control Services.

The AER rejected our PTRM inputs and substituted its own inputs – without the inclusion of the contributed and gifted capital expenditure mentioned above. While this had no effect on the calculation of depreciation and rate of return building blocks, it resulted in the allowance for corporate income tax to be understated.

3.1.5. Depreciation approach

The AER determined to apply the forecast depreciation approach to establish the opening RAB value as at 1 July 2020.

[4] *03.01.01 – Building Block components*, p32.

3.2. Stakeholder feedback

In its Issues Paper, the AER stated that our RAB is continuing to grow, despite lower capital expenditure being proposed and weak demand forecasts.[5] The AER indicated that it will investigate this issue. The CCP also raised similar concerns at the public forum held on 9 December 2014.[6]

A number of stakeholders requested the AER to carefully examine past and proposed capital expenditure to ensure expenditure is prudent and efficient.[7] The Bundaberg Regional Irrigators Group surmised that the RAB is "guaranteeing profits and escalating price increases".[8] Stakeholders also suggested that the RAB should be re-valued.[9]

Some stakeholders also called on the AER to review the existing rules for determining the RAB, such as the application of an annual CPI adjustment.[10]

Finally, the Urban Development Institute of Australia and Australians in Retirement organisation queried whether gifted assets are included in the RAB.[11]

3.3. Other influencing factors

Ergon Energy has more up-to-date capital expenditure, disposal and regulatory depreciation estimates for 2014-15 than those relied on by the AER in its Preliminary Determination. These estimates affect the opening RAB value.

Proposed changes to our forecast capital expenditure and inflation rates also impact the forecast RAB values.

3.4. Our response

3.4.1. Summary

Ergon Energy has revised the RAB in our Regulatory Proposal to account for amendments we have made to capital expenditure, inflation and the rate of return. Our approach on these inputs is outlined in other chapters. Our opening RAB value has also been amended to reflect updated 2014-15 estimates.

We have reviewed the AER's determination in relation to equity raising costs, opening remaining asset lives and disposals. In response, we have:

- updated our opening RAB such that it is determined using the remaining lives as of 1 July 2009 (calculating using the average depreciation approach) and our proposed

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[5] AER (2014), *Issues paper: Qld electricity distribution regulatory proposal 2015–16 to 2019–20,* December 2014, pp9, 11 and 19.
[6] Bruce Mountain, Op. cit, p3.
[7] Darling Downs Cotton Farmers (2015), *RE: QLD Electricity Distribution Regulatory Proposals 2015-2020,* 29 January 2015, p1; Cotton Australia, Op. cit, p8; and Canegrowers Isis (2015), *Re: Qld electricity distribution regulatory proposals 2015-16 to 2019-20,* 30 January 2015, p3.
[8] Bundaberg Regional Irrigators Group (2015), *Re: Submission to AER regarding Ergon Energy's regulatory proposal,* 30 January 2015, p3.
[9] Canegrowers (2015), *Ergon Energy and Energex – Network Distribution Resets 2015-20,* 30 January 2015, p4; Canegrowers Isis, Op. cit, p2; Electrical Trades Union of Australia (2015), *Energex and Ergon Regulatory Proposals 2015-20 and Issues Paper,* January 2015, p5; and National Irrigators' Council (2015), *Re: Submission to the AER Queensland electricity distribution regulatory proposals 2015-16 to 2019-20,* 30 January 2015, p2.
[10] See, for example, Cotton Australia, Op. cit, p8.
[11] Urban Development Institute of Australia Queensland (Cairns Branch) (2015), *Urban Development Institute of Australia Queensland (Cairns Branch) Submission to the AER on Ergon Energy's Regulatory Proposal 2015-2020*, 29 January 2015, p2; and Australians in Retirement – Cairns and District Branch (2015), *A Submission to the AER From the Cairns and District Branch of Australians in Retirement*, 28 January 2015, p2.

weighted average remaining life (WARL) for actual and estimated capital expenditure incurred between 2009-10 and 2014-15 inclusive

- revised our approach to estimating equity raising costs consistent with the AER's methodology
- changed our approach to calculating the remaining lives at the beginning of the regulatory control period 2015-20. However, we have not adopted the AER's methodology. Our approach will reduce the depreciation allowance in this period and increase the value of the RAB in 2020 compared to our October Regulatory Proposal. On the other hand, the AER's methodology would have increased the value of the RAB in 2020 even higher. More information on our proposed approach can be found in Section 4.3 below.

The above changes have been made in the following documents:

- Chapter 3 of the revised Regulatory Proposal
- *03.01.01 – (Revised) Ergon Energy's Building Block Components*
- *03.01.04 – Post Tax Revenue Model (January 2015).*
- *03.01.06 – Roll Forward Model.*

3.4.2. Opening RAB

We have not updated our proposal to reflect the AER's decision to reduce the value of the RAB for previous investments which provide Alternative Control Services. The AER has mischaracterised Ergon Energy's position in this regard. When asked to provide the adjustments we believed necessary to remove the value of assets providing Alternative Control Services, we clearly set out our opposition to this approach as the AER has no power to do this under the NER.[12] Nevertheless, we provided the information to assist the AER to make the reductions after we were advised the AER would make its own adjustments if we did not provide updated estimates. This does not constitute an agreement, which the AER has implied in its Preliminary Determination. We remain opposed to the AER's approach and have not updated our proposal to reflect it.

Finally, Ergon Energy notes the AER's position to apply the forecast depreciation approach to establish the opening RAB as at 1 July 2020.

3.4.3. Rolling forward RAB into 2020

By virtue of the operation of the Standard Control Services PTRM, inclusion of gifted and contributed assets in the PTRM ensures that we receive the tax allowance we require to recover the tax payable for contributed and gifted assets from large customer connections during the regulatory control period 2015-20. This is because row 39 of the Analysis tab in the PTRM includes the capital contributions as additional tax income, and row 43 of the Analysis tab in the PTRM uses the value of capital contributions in determining the tax depreciation for each regulatory year.

In this way, the contributed and assets from large customer connections during the regulatory control period 2015-20 are included in the tax expense and tax payable calculations in the PTRM (and hence the ARR for Standard Control Services).

By the same token, the exclusion of these assets from the calculation does not allow Ergon Energy to recover the tax we must pay for gifted and contributed assets we receive during the period.

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[12] Ergon Energy (2015), *Response to AER Information Request: AER Ergon 060*, 23 February 2015, p2.

Ergon Energy recognises that this was in fact the situation in the regulatory control period 2010-15. In effect, the tax paid as a result of the contributed and gifted assets we received from large customer connections was not able to be recovered from either the Standard Control Service revenue requirement or any of the Alternative Control Service pricing mechanisms approved by the AER in the 2010-15 Distribution Determination. This approach is inconsistent with the NER and National Electricity Law (NEL) and with practice in other jurisdictions.

We will not be recovering these foregone costs in the regulatory control period 2015-20. However, it is important for the AER to properly recognise our opportunity to legitimately recover any forecast tax payable as a result of the contributed and gifted assets we expect to receive from large customer connections in the regulatory control period 2015-20.

4. Regulatory depreciation

4.1. Preliminary Determination

The AER did not accept our proposed regulatory depreciation allowance of $903.94 million for the regulatory control period 2015-20. It determined an allowance of $654.6 million.

4.1.1. Depreciation approach

The AER supported our proposed straight-line depreciation method to determine the regulatory depreciation allowance set out in the PTRM and the proposed standard asset lives. However, it rejected our proposal to use the proposed average depreciation method to calculate the remaining asset lives as at 1 July 2015.

4.1.2. Standard asset lives

The AER accepted our proposed standard asset lives for our existing asset classes. The standard asset lives were the same as those approved by the AER for the regulatory control period 2010-15. However, it updated the standard asset life for the 'Equity raising costs' asset class to reflect changes it made to the opening RAB. The AER applied the same weighted average approach to determining the standard asset life as approved for the regulatory control period 2010-15.

4.1.3. Remaining asset lives

The AER did not accept our proposed average depreciation approach to calculating the remaining asset lives as at 1 July 2015. Instead, the AER used the WARL approach. The AER believes its approach results in remaining asset lives that better reflect the nature of the assets over their economic lives. Further, this approach is consistent with the approach taken by other service providers.

4.2. Stakeholder feedback and other influencing factors

There has been no stakeholder feedback received on regulatory depreciation. However, we noted above there have been strong stakeholder concerns regarding the high RAB value. In reviewing the AER's decision on depreciation approach, we have also reviewed depreciation approaches taken by other Network Service Providers (NSPs).

4.3. Our response

4.3.1. Summary

The AER's Issues Paper to our Regulatory Proposal noted that Ergon Energy's RAB increased by around 27 per cent. In the Issues Paper, the AER stated it will investigate why the RABs are proposed to continue to grow so significantly.[13] Ergon Energy noted in our response to the AER's Issues Paper that the regulatory framework is a key contributor to increasing RAB values.[14] In effect, the indexation of the RAB is a deferral of returns back to Ergon Energy from our investment. This has the effect of deferring revenue recovery from the current period and into future periods through

[13] AER (2014), *Issues paper, Qld electricity distribution regulatory proposals 2015–16 to 2019–20*, December 2014, p19.
[14] Ergon Energy (2015), *Submission on the Queensland electricity distribution regulatory proposals 2015–16 to 2019–20 Issues Paper*, 30 January 2015, p4.

inflating the RAB. This, along with other historic regulatory treatments does create intergenerational equity issues over time.

Ergon Energy's approach to calculating remaining lives for assets at the beginning of the period is consistent with the approach approved by the AER in 2010. The AER's decision to reject Ergon Energy's methodology in favour of another approach has the effect of inflating the RAB at the end of the period.

In support of this approach, the AER provided analysis which suggested that, compared to the AER's preferred methodology of calculating remaining lives, Ergon Energy's approach increases the annual depreciation allowance and returns the value of the asset quicker.[15] The AER's argument is that an approach that under-estimates the remaining lives of the assets results in assets being fully depreciated before the end of their useful lives. In turn, this may encourage inefficient use and early replacement of assets inconsistent with the NEL.

We have attempted to replicate the AER's analysis and note that it does not appear to consider other impacts on the RAB roll-forward – namely the Consumer Price Index (CPI) indexation – when considering the impact on the depreciation profile of assets. Ergon Energy believes this regulatory arrangement over-estimates the remaining lives of assets and has the risk of assets not being fully depreciated until after the end of their useful lives.

When combined with a WARL approach, under which old and new assets are combined in each asset class, the likelihood of residual asset values remaining in the RAB past their economic life is even greater. The result is an increased risk of future generations paying more as they are paying for assets that have since been replaced.

It is important to note that the return of the asset is Net Present Value (NPV) neutral. Customers do not pay more or less in NPV terms under either approach. Nevertheless, we consider the AER approach has a tendency to inflate the RAB more than necessary and this is something our customers do not want.

Notwithstanding our concerns that the AER's proposed direction may not be in the long term interests of customers when a broader range of factors are taken into account, Ergon Energy has revised our proposal to:

- address the issues identified by the AER in its Preliminary Determination, and
- be more consistent with other NSPs and their approach to remaining lives.

Our revised approach is outlined in more detail in our supporting document *03.03.01 – (Revised) Building Block Components*. In summary, our revised approach involves:

- creating asset classes for:
    - assets installed pre 2009-10
    - assets installed post 2009-10
- applying the AER's preferred WARL approach to these asset classes, modified such that the WARL extends to capital expenditure from 2009-10 to 2014-15 inclusive

[15] AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 5 – Regulatory depreciation*, April 2015, p14.

- calculating the remaining lives for assets pre-2009-10 using the average depreciation approach. The AER used 2010-11 as the first year of capital expenditure for the WARL calculation, and hence it used the remaining lives of assets as at 1 July 2010. Ergon Energy has used 2009-10 as the first year of capital expenditure for the WARL calculation, and hence has calculated the remaining lives for assets as of 1 July 2009 using the average depreciation approach. This therefore differs with the remaining lives substituted by the AER for 1 July 2010 in the Preliminary Determination
- using the AER's standard lives as set out in the Preliminary Determination for assets post-2009-10 in the WARL calculation.

Ergon Energy's approach for calculating the WARL is generally consistent with the AER's preferred approach set out in the Preliminary Determination. However, Ergon Energy's WARL calculations differ from the AER's approach set out in the Preliminary Determination in the following ways:

- Separate asset classes have been created for assets pre and post 1 July 2009. This differs from the asset classes used by the AER in its Preliminary Determination.
- The WARL is applied to capital expenditure from 2009-10 to 2014-15 inclusive, not 2010-11 to 2014-15 inclusive as proposed by the AER.

These differences, and why Ergon Energy considers these to be consistent with the NER, are described in more detail below.

Ergon Energy's proposed asset classes differ to those accepted by the AER in its Preliminary Determination

While the assets grouped into each asset class have not changed, Ergon Energy has effectively split each of our existing asset classes into two, in order to cater for assets installed pre 2009-10 and post 2009-10. To distinguish between the pre and post 2009-10 asset classes, Ergon Energy has appended the label "2009-15" to each of the asset classes corresponding to asset installed post 1 July 2009.

This is consistent with the approach taken by other NSPs to group assets by regulatory control period and we note that the AER has approved this approach in previous regulatory determinations. It is also consistent with the requirements of clause 6.5.5(b)(1) of the NER, which requires that the depreciation schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets. Splitting the asset classes by regulatory control period preserves the nature of the assets being depreciated (for example, assets in the Distribution Substations 2009-15 asset class are of the same type as those in the Distribution Substations asset class), while more accurately calculating the remaining life of the assets both pre and post 2009-10 over the economic life of the asset class.

Despite the change in asset classes between the regulatory control period 2010-15 and the regulatory control period 2015-20, there is no "disconnect" between regulatory control periods. This is because we have not removed or changed any of the existing asset classes in the 2010-15 regulatory control period, and the total value of the assets classes pre 2009-10 and post 2009-10 can still be added together to give a single opening RAB value as of 1 July 2015.

The WARL is applied to capital expenditure from 2009-10 to 2014-15 inclusive, not 2010-11 to 2014-15 inclusive as proposed by the AER.

Ergon Energy has applied the WARL to capital expenditure from 2009-10 to 2014-15 inclusive, rather than 2010-11 to 2014-15 inclusive as set out in the AER's Preliminary Determination. Ergon Energy has extended the AER's WARL approach to 2009-10 because:

- actual capital expenditure for 2009-10 by asset class is recorded in the RFM in the same way as actual capital expenditure from 2010-11 to 2014-15
- given that 2009-10 actual capital expenditure data is available, it would be inconsistent not to apply the WARL approach to capital expenditure from 2009-10 to 2014-15
- using 2009-10 actual capital expenditure removes the need to correct for the difference between forecast and actual capital expenditure in 2009-10 when calculating the 1 July 2015 remaining lives, including 2009-10, gives an additional year of capital expenditure granularity in the WARL calculation, thereby:
    - improving the accuracy of the WARL
    - minimising the impact of averaging asset values and lives over time, and better reflecting the mix of depreciated assets in the RAB as at 1 July 2015.

We also rely on addition evidence from Brendan Quach of Houston Kemp who has provided advice on alternative approaches to calculating remaining lives. In the supporting document, *Houston Kemp – Analysis of Different Approaches to Calculating Remaining Lives*, Mr Quach makes the following observations:

- A single remaining asset life cannot generate a depreciation allowance that accurately reflects a group of assets with disparate economic lives. Consequently, depreciation schedules that are generated by combining existing assets (with short remaining lives) and new capital expenditure will result in substantial intergenerational equity issues.
- The AER's conclusion that the WARL approach results in a balanced outcome (to the average depreciation approach) in the long run is not supported on the evidence – the WARL approach will result in substantial intergenerational equity issues, with customers periodically either underpaying or overpaying the capital related costs of each asset group.

We note that our revised approach to calculating depreciation is consistent with one of the approaches Mr Quach recommended:[16]

> the WARL of 2009-15 capex approach, which separately calculates for each asset category the economic lives of existing assets and new capex incurred during 2009 to 2015 period thereby avoiding the distortions associated with combining assets with disparate economic lives.

[16] Quach (HoustonKemp) (2015), *Analysis of Different Approaches to Calculating Remaining Lives*, p21.

5. Corporate income tax

5.1. Preliminary Determination

The AER did not accept our proposed cost of corporate income tax. Instead, the AER applied an allowance of $204.2 million, which is a 67.1 per cent reduction. This reflects adjustments the AER made to:

- the opening tax asset base (TAB) value as at 1 July 2015
- the remaining tax asset lives
- gamma
- other building block components (e.g. operating expenditure and capital expenditure).

5.1.1. Opening tax asset base

While the AER accepted our approach to establishing the opening TAB as at 1 July 2015, it did not accept our proposed value. It substituted an opening TAB of $6,377.8 million, an increase of $52.7 million. This increase reflects adjustments made to the actual capital expenditure values in our Roll Forward Model.

5.1.2. Remaining tax asset lives

The AER did not accept our proposed approach to estimating the remaining tax asset lives at 1 July 2015. The AER has determined the remaining tax asset lives using a weighted average approach. This involves rolling forward the approved remaining tax asset lives at the start of the regulatory control period 2010-15 having regard for the amount of actual capital expenditure in that period. The AER was concerned that our average depreciation approach tends to result in lower lives.

5.1.3. Standard tax asset lives

The AER accepted our proposed standard tax asset lives. This is because they are consistent with those approved in the regulatory control period 2010-15 and the values prescribed by the Australian Taxation Office. However, it updated the standard tax asset life for the ‘Equity raising costs’ asset class to five years.

5.2. Stakeholder feedback

On our review, there was limited feedback from customers on corporate income tax. Cotton Australia called on the AER to closely examine the way it determines allowances for taxation equivalents and the like.[17]

5.3. Other influencing factors

There is an obvious link between arrangements for the TAB and the underlying RAB. Changes to capital expenditure and depreciation will influence outcomes. Our response to tax asset lives is strongly influenced by our response to the AER’s Preliminary Determination on regulatory depreciation (refer to Chapter 4).

[17] Cotton Australia, Op. cit, p12.

5.4. Our response

We have revised our regulatory proposal for calculating tax asset remaining lives consistent with our revised approach to regulatory depreciation, as set out in section 4.3.1 above. Our revised approach is outlined in our revised Regulatory Proposal and in section 4.2.4 of our supporting document *03.03.01 – (Revised) Building Block Components*.

We also rely on additional evidence from Houston Kemp who have provided advice on alternative approaches to calculating remaining lives. Please refer to *Houston Kemp – Analysis of Different Approaches to Calculating Remaining Lives* for further details.

6. Control mechanism and pricing

6.5. Preliminary Determination

6.5.1. Application of the revenue cap

Consistent with the Framework and Approach Paper and our October Regulatory Proposal, the AER decided to apply a revenue cap to Standard Control Services. The revenue cap for any given year is the Total Annual Revenue (TAR) plus any adjustment required to move the DUOS unders and overs account to zero.

The AER accepted our proposal to include:

- the final carryover amount for the 2010-15 Demand Management Incentive Scheme (DMIS) in the incentive scheme adjustment
- the under- or over-recoveries relating to capital contributions and shared assets from 2013-14 and 2014-15 in the B-factor
- FiT cost pass through amounts relating to 2013-14 and 2014-15 in the C-factor
- amounts relating to the occurrence of our prescribed and nominated pass through events in the C-factor.

However, the AER did not accept our proposal to include:

- the annual adjustment for the Service Target Performance Incentive Scheme (STPIS) in the incentive scheme adjustment. Instead, the AER included this adjustment in the calculation of AR_t
- the DUOS under- and over-recovery adjustments in the B-factor. Consistent with the regulatory control period 2010-15, this will occur outside of the TAR formula
- other one-off revenue adjustments approved by the AER in the C-factor. The AER considers that a general 'catch all' definition is not consistent with incentive regulation and increases uncertainty and administration costs in the annual pricing proposals.

In its Preliminary Determination, the AER also decided to deal with changes to revenue resulting from the annual return on debt update through the X-factors.

6.5.2. Under and over recovery mechanism for DUOS

The AER decided to apply an unders and overs mechanism, consistent with the approach taken in the regulatory control period 2010-15 and our initial Regulatory Proposal.

Our initial Regulatory Proposal also included a principles-based approach to tolerance limits. The AER did not approve the use of tolerance limits in its Preliminary Determination. Rather, it expects the closing balance of the DUOS unders and overs account in year t must be zero. The AER stated the risks of applying tolerance limits, such as delayed price shocks and reduced cost reflectivity in prices, outweigh the benefits of potentially smoothing prices.

Ergon Energy must demonstrate compliance with the DUOS unders and overs account set out in Appendix A of Attachment 14 of its Preliminary Determination in our annual Pricing Proposal.

6.5.3. Under and over recovery mechanism for TUOS

Similar to DUOS, the AER decided to apply an unders and overs mechanism for TUOS. Consistent with the regulatory control period 2010-15, the AER requires the closing balance of the TUOS unders and overs account in year t to be zero.

Ergon Energy must demonstrate compliance with the TUOS unders and overs account set out in Appendix B of Attachment 14 of its Preliminary Determination in our annual Pricing Proposal.

Chumvale and Powerlink charges

In our October Regulatory Proposal, we proposed to recover charges associated with the use of the Chumvale and Powerlink lines through our operating expenditure allowance. However, the AER considers these charges should continue to be recovered as designated pricing proposal charges. Specifically, the AER indicated the use of the Chumvale and Powerlink lines are 'prescribed exit services', which are included in the NER definition of designated pricing proposal charges.

The AER also suggested that the non-prescribed Powerlink connection services are already prescribed.

6.5.4. Reporting on jurisdictional scheme amounts

Ergon Energy proposed to apply a two year lag to the recovery of costs associated with FiT payments made under the Queensland Government Solar Bonus Scheme. In terms of reporting, we proposed to set out in our annual Pricing Proposal:

- the jurisdictional scheme amounts that we will recover from customers for the relevant regulatory year
- how those amounts will be passed on to our customers.

We proposed that actual FiT payments made in year t would be recovered in year t+2. The amount to be recovered would be adjusted for the time cost of money by applying the relevant WACC for the two years of the lag between when we incur the cost and when we recover those costs from our customers.

The AER did not accept our proposed method of reporting on the jurisdictional scheme amounts, as it rejected our proposed two year lag approach. The AER considered this approach to be a significant departure from the national approach to the recovery of jurisdictional scheme amounts and is also not consistent with the NER's emphasis on cost-reflective pricing. Instead, the AER requires Ergon Energy to provide a jurisdictional scheme unders and overs account in our annual Pricing Proposal. This account is set out in Appendix C of Attachment 14 of its Preliminary Determination.

The AER requires the closing balance of the jurisdictional schemes unders and overs account in year t to be zero.

6.5.5. Side constraints

For each year after 2015-16, the AER determined to apply side constraints to the weighted average revenue to be raised from each tariff class. The permissible percentage increase is the greater of CPI-X plus 2 per cent or CPI plus 2 per cent. Recovery of certain revenues such as those to accommodate cost pass throughs is disregarded in deciding whether the permissible percentage has been exceeded.

6.5.6. Control mechanism formulas

Revenue cap

Ergon Energy will be required to demonstrate in our annual Pricing Proposal that our revenues are consistent with the formulae set out below, plus any unders and overs adjustment required to move the balance of our DUOS unders and overs account to zero.

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

2 $$TAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$$ i=1,...,n and j=1,...,m and t=1,...,5

3 $$TAR_t = AR_t \pm I_t \pm B_t \pm C_t$$

Where:

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

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

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

S_t is the STPIS factor sum of the raw s-factors for all reliability of supply and customer service parameters (as applicable) to be applied in year t

TAR_t is the total annual revenue in year t

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

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

I_t is the final carryover amount from the application of the DMIS from the 2010-15 distribution determination. This amount will be deducted from/added to allowed revenue in the 2016-17 pricing proposal

B_t is any under or over-recoveries relating to capital contributions and shared assets from 2013-14 and 2014-15

C_t is the sum of adjustments related to:

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

Side constraints

Ergon Energy will be required to demonstrate in our annual Pricing Proposal that proposed DUOS prices for the next year (t) meet the following side constraints formula for each tariff class:

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

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

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

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

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

ΔCPI_t is the annual percentage change in the ABS [Australian Bureau of Statistics] CPI All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1

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

S_t is the STPIS factor sum of the raw s-factors for all reliability of supply and customer service parameters (as applicable) to be applied in year t

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

B_t is any under or over-recoveries relating to capital contributions and shared assets from 2013-2014 and 2014-2015

C_t is the sum of adjustments related to:

- feed-in tariff cost pass through amounts relating to 2013-2014 and 2014-2015
- amounts relating to the occurrence of any of the prescribed and nominated cost pass through events

$DUoS_t$ is an annual adjustment factor related to the balance of the DUoS unders and overs account with respect to regulatory year t.

6.5.7. Assigning retail customers to tariff classes

The AER considered our initial Regulatory Proposal contained an effective system for assessing and reviewing the basis on which a customer is charged. However, the AER amended our procedures for assigning and reassigning retail customers to tariff classes to ensure retail customers are referred to the Queensland Energy and Water Ombudsman if they disagree with the assignment or reassignment (to the extent such a resolution is within the jurisdiction of the Ombudsman).

6.6. Our response

Ergon Energy does not agree with several aspects of the AER's Preliminary Determination on the control mechanism applying to Standard Control Services. Our key concerns relate to:

- the revenue cap formula

- the under and over recovery mechanism for DUOS, including the AER's decision not to apply tolerance limits
- the recovery of jurisdictional scheme amounts
- assigning and reassigning retail customers to tariff classes.

We have applied the AER's interpretation of the NER in relation to Chumvale and non-prescribed Powerlink connection points. That is, we have treated these costs as designated pricing proposal charges.

Our detailed response on the control mechanism applying to Standard Control Services is provided in the following sections.

6.6.1. Application of the revenue cap

Ergon Energy has revised our proposal to reflect the AER's preliminary decision to:

- include the carryover amount associated with the operation of the DMIS in the regulatory control period 2010-15 in the I_t component as this is consistent with our October Regulatory Proposal
- include under or over-recoveries relating to capital contributions and shared assets from 2013-14 and 2014-15 in the B_t component, in accordance with our initial proposal
- include adjustments relating to cost pass throughs, including FiT cost through amounts relating to 2013-14 and 2014-15, in the C_t component since this aligns with our initial proposal
- address the annual updates to the return on debt through the X-factors.

However, we disagree with the AER's position in relation to:

- the S-factor associated with our performance under the STPIS. Ergon Energy considers that rewards or penalties should be included in the I_t component. Our reasons for this are discussed below.
- DUOS under and over-recovery adjustments. Ergon Energy does not support a departure from the formula contained in the Framework and Approach Paper (refer to Section 6.6.4). Therefore, we consider DUOS under and over-recovery adjustments should be included in the B_t component
- other one-off revenue adjustments. In the regulatory control period 2010-15, Ergon Energy was directed by the Queensland Government to forgo revenue associated with:
  - the 2011 Electricity Network Capital Program. Specifically, Ergon Energy was directed to not recover $99.18 million of our AER-approved revenue allowances for the remainder of the regulatory control period (i.e. 2012-13 to 2014-15). We made adjustments for this in our 2012-13 and 2013-14 Pricing Proposals, which were approved by the AER.
  - gamma. Ergon Energy received a direction to not pass on the Standard Control Services 2011-12 revenue increases arising from the Australian Competition Tribunal's decision on gamma. The amount of the 2011-12 smoothed revenue attributable to the gamma decision was $40.9 million. This adjustment was approved by the AER in our 2011-12 Pricing Proposal.

We also consider that this component is required to cater for any true-up adjustments between the Preliminary Determination and the Substitute Determination, where the adjustment is unable to be accounted for within other parameters of the revenue cap formula. For example, it is unclear how the AER intends to deal with the true-up of any STPIS revenue adjustments already passed through to customers in annual pricing as a result of changes to the five year allowable revenues. In addition, this component provides the AER with flexibility to address any future errors, changes and omissions without the administrative burden of revoking and substituting the revenue determination

Ergon Energy considers the revenue cap formula should be flexible enough to allow such adjustments to be passed through to customers. Further, we consider the administrative costs of assessing such an adjustment are not material enough to warrant not including this factor in the revenue cap formula. We are not aware of any issues experienced by the AER in processing such adjustments in the past. However, we are aware of the administrative burden when a determination is struck and there are problems with the control mechanism, but the formulaic approach is so rigid that the AER is forced into a position where it must revoke and remake a decision. Having more flexibility in the formula would appear to be in the customers' best interest.

Finally, as highlighted in our October Regulatory Proposal, this adjustment factor would only be used in extremely limited circumstances.

Ergon Energy has maintained our initial approach on the above matters in our revised Regulatory Proposal.

Tolerance limits

In its Preliminary Determination, the AER has not applied tolerance limits for the regulatory control period 2015-20, on the basis that it considers *"the risk of applying tolerance limits (delayed price shocks, and reduced cost reflectivity in prices) outweigh the benefits of potentially smoothing prices"*.[18] More specifically, the AER has raised concerns that the use of tolerance limits could result in large adjustments accumulating over the regulatory control period which ultimately delays, rather than eliminates, price shocks. Further, that accumulation of adjustments could distort the cost-reflectivity of tariffs and therefore price signals to customers for efficient usage.

Ergon Energy maintains our view that a principles-based approach to tolerance limits assists to reduce price volatility over time. The AER has adopted smoothing arrangements at the beginning of the regulatory control period to minimise the impact for customers. We see no reason why a smoothing approach within a regulatory control period should be rejected. Where an accumulated balance carries over to the next regulatory control period, with agreement by the AER, the balances could be recovered over two or three years rather than being cleared in the first year. The size of the price shock will always be lower if the amount is recovered over two or three years compared to being recovered in one year.

Regarding cost-reflectivity of tariffs in accordance with the pricing principles in clause 6.18.5 of the NER, this clause does not specify that the tariffs must reflect the cost of supply in each individual year. Distribution assets are generally long term in nature; therefore, it seems reasonable that the principle holds for charges to customers to reflect costs over time. The allowance for unders and overs in itself recognises that the revenue recovered from customers will not represent the efficient costs in each individual year.

In addition, clause 6.18.5(h) of the NER requires a Distribution Network Service Provider (DNSP) to consider the impact on retail customers of changes in tariffs from the previous year and can vary compliance with the pricing principles under this clause to the extent that the DNSP considers reasonably necessary, having regard to:

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[18] AER (2015), *Preliminary Decision, Ergon Energy determination 2015–16 to 2019–20, Attachment 14 – Control mechanisms*, April 2015, p11.

(1) the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one *regulatory control period*);

(2) the extent to which *retail customers* can choose the tariff to which they are assigned; and

(3) the extent to which *retail customers* are able to mitigate the impact of changes in tariffs through their usage decisions.

Application of tolerance limits, with an intention to smooth price shocks over time (including between regulatory control periods), is an example of Ergon Energy's compliance with this rule.

In the event that the AER confirms its decision not to apply tolerance limits, Ergon Energy proposes a t-1 methodology for calculating the DUOS unders and overs account balance. This aligns with the final decisions for the regulatory control period 2014-19 for the New South Wales (NSW) DNSPs. That is, the clearance of DUOS unders and overs in year t is based on the audited closing balance in year t-2 and an estimate of the closing balance in year t-1. This provides another mechanism to potentially minimise price shocks, as there will be early notification of potential unders and overs in year t-1 that can be brought into calculations for year t. This should help to reduce balances in year t-2.

An illustration of the DUOS unders and overs account under this approach is contained in our supporting documents, *04.00.00 – (Revised) Compliance with control mechanisms* and *04.01.05 – (Revised) Control mechanism model*.

Designated pricing proposal charges

We note that the non-regulated 220kV line to Cloncurry is owned by Ergon Energy and therefore does not meet the definition of a prescribed transmission service. Transmission services are defined generally under the NER as services provided by a transmission network, which in turn is defined by reference to the nominal operating voltages. However, the transitional arrangements set out in clause 9.32.1(b) of the NER alter the definition of a transmission network for those networks located in Queensland. Specifically, transmission networks in Queensland include only those assets owned by Powerlink or a holder of a transmission authority. Ergon Energy does not hold a transmission authority and none of our networks are therefore considered transmission networks for the purposes of the NER, irrespective of the nominal operating voltage. Hence, the network services provided by Chumvale are not prescribed transmission services.

However, we will treat these costs as designated pricing proposal charges consistent with the AER's Preliminary Determination. We note that these costs fit within the intent of the designated pricing proposal charges, namely the pass through of charges for certain services provided by other DNSPs.

We note that there may be some uncertainty as to whether the entry and exit services provided by Powerlink at the specific connection points are prescribed transmission services, and therefore meet the definition of designated pricing proposal charges. However, Ergon Energy agrees to treat these charges as designated pricing proposal charges consistent with the AER's Preliminary Determination. We note that Powerlink intends for these connection points to be included in its regulated asset base for its next regulatory control period, at which time those services will be prescribed transmission services and the associated costs recoverable as designated pricing proposal charges.

The above costs have been removed from our operating expenditure forecast and will be reflected in the TUOS charges.

These changes have been reflected in:

- Chapter 4 and Appendix A of the Regulatory Proposal – specifically, we have removed these costs from operating expenditure and identified them as designated pricing proposal charges
- *04.01.01 – (Revised) Designated Pricing Proposal Charges*
- *06.01.01 – (Revised) Operating Forecast Expenditure Summary Document*.

6.6.2. Reporting on jurisdictional scheme amounts

The AER rejected our proposal to apply a two-year lag on the jurisdictional scheme amount recovery. However, Ergon Energy does not consider there is any basis for rejecting this proposal.

Clause 6.18.7A of the NER prescribes a number of requirements that must be satisfied in relation to the recovery of jurisdictional scheme amounts in a pricing proposal. Further details of our interpretation of this clause (and its associated sub-clauses) are set out in detail in section 17.3.3 of our main submission, *Submission to the AER on its Preliminary Determination*.

It is apparent from the drafting of clause 6.18.7A of the NER that the method for determining the over and under recovery amount, referred to in clause 6.18.7A(c) of the NER, is central to the operation of Ergon Energy's proposed framework.

In 2011, clause 6.18.7A of the NER was amended to give greater flexibility to the AER in determining the method by which the 'true up' would be calculated.[19] In its report explaining its reasons for these amendments, the Australian Energy Market Commission (AEMC) stated:

> "…the Commission noted that there are significant differences in the current true-up adjustment methodology between DNSPs. This means that the prescribed level of detail in the draft Rule for the true-up provision will be difficult for DNSPs to implement and lead to consequential differences with current practices which may make DNSPs either worse off or better off.
>
> On balance, the Commission considers that there is a need for a consistent approach and that a high level principles-based approach can achieve this. This approach will allow the AER and DNSPs the flexibility and clarity to determine how to make true-up adjustments."[20]

The critical word in this passage is 'flexibility'. The AEMC intended that a DNSP would have the flexibility to propose, and the AER would have the flexibility to approve, any suitable method for determining how to make true-up adjustments, provided that it satisfies the principles laid down in clause 6.18.7A(c) of the NER. This feature of the regime, coupled with the requirement that the amount to be passed through under the pricing proposal not exceed the limit established by clause 6.18.7A(b) of the NER, supports the alternative framework proposed by Ergon Energy.

Our proposed approach is also consistent with the pass through arrangements the AER adopted in its 2010-15 Distribution Determination. If the AER had legitimate concerns with what Ergon Energy is now proposing, it would never have adopted the regime it currently has in the first place. There is

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[19] See *National Electricity Amendment (DNSP Recovery of Transmission-related Charges) Rule*, Rule 2011 No 1.
[20] AEMC (2011), *DNSP recovery of transmission-related charges, Rule Determination*, 24 March 2011, pp37-38.

also considerable precedent in other elements of the determination where recovery is only made on the actual audited financial information.

Ergon Energy also proposes that an unders and overs account is required to deal with the difference between actual jurisdictional scheme payments and jurisdictional scheme revenues, similar to that applied for both DUOS and TUOS under and over recoveries. This is set out in section 6.6.7 below.

6.6.3. Side constraints

Ergon Energy accepts the AER's decision to apply side constraints to the weighted average revenue to be raised from each tariff class for each year after 2015-16. We note this requirement is consistent with clause 6.18.6(b) of the NER. Our comments on the side constraints formula are provided in Section 6.6.4 below.

6.6.4. Control mechanism formula

Revenue cap formula

Ergon Energy has not applied the revenue cap formula contained in the Preliminary Determination. The reason for this is twofold:

1. The AER has departed from the revenue cap formula provided in the Framework and Approach Paper, [21] without providing justification for this departure.
2. The revenue cap formula contains an error and cannot be applied in practice.

Each of these points is discussed below.

No justification for departure from the Framework and Approach

Under clause 6.12.3(c1) of the NER, the AER must apply the formula set out in the Framework and Approach Paper unless the AER considers that unforeseen circumstances justify departing from the formulae. The AER did not provide any such justification in its Preliminary Determination.

Ergon Energy liaised extensively with the AER at the time of the Framework and Approach to ensure the revenue cap formula enabled us to recover our allowed revenue plus other annual revenue adjustments approved by the regulator, and was able to be applied in practice.

The formula in the Framework and Approach Paper achieved this. Therefore, we consider there is no reason to depart unless there is an error in the formula.

Practical application

Because it chose not to adopt the control mechanism agreed to through its own Framework and Approach process, the AER's preliminary decision on the revenue cap formula contains an error which, if followed literally, would mean Ergon Energy would not be able to pass through any DUOS under or over recoveries in our proposed tariffs. This is because the definition of the TAR in equations 2 and 3 in the AER's formula excludes any DUOS under and over recoveries from previous years. However, Ergon Energy must demonstrate that our proposed tariffs (which necessarily include any under and over adjustments needed to move the balance of the DUOS unders and overs account to zero) is less than or equal to the TAR.

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[21] AER (2014), *Final Framework and approach for Energex and Ergon Energy, Regulatory control period commencing 1 July 2015*, April 2014, p63.

On 20 May 2015, the AER wrote to Ergon Energy advising that the “formula should include ± $DUoS_t$ at the end of the TAR_t formula” and that our 2015-16 Pricing Proposal should reflect this correction.[22] Further, the AER indicated that the issue would be fixed in the Substitute Determination. A similar issue was identified in the Final Decision for NSW distributors.[23]

In our 2015-16 Pricing Proposal, Ergon Energy included the $DUoS_t$ component in the second equation of the revenue cap formula:

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

We did this because it is more consistent with the wording of Attachment 14 of the Preliminary Determination which refers to the revenue cap as “the TAR for that regulatory year plus any adjustment required to move the DUOS under/over account to zero”. However, Ergon Energy considers the issue could be more simply addressed by including any DUOS under or over recoveries in equation 3. This would also be consistent with the AER’s initial approach of including these amounts within the B_t component in the Framework and Approach Paper.

In addition to this error, Ergon Energy considers the approach of calculating and including a revenue adjustment within the I_t component of the revenue cap formula is more appropriate. This is consistent with the current approach and the Framework and Approach Paper. The proposed change to include the S-factor in the AR_t component would be administratively complex. This is because Ergon Energy will need to transition to applying additional calculations to remove the impact of previous year’s factors, the mathematics of which is complicated by the inclusion of other revenue items in the opening AR_t and STPIS adjustments for impacts of step changes in revenues in transitioning between regulatory control periods.

Proposed formula

In light of the above, Ergon Energy proposes the following revenue cap formula:

Revenue cap (as determined by the PTRM):

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

Total allowed revenue (including adjustments):

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

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

Where:

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

ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from December in year t–2 to December in year t–1

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[22] AER (2015), Letter to Mr Gordon Taylor (Acting Chief Executive, Ergon Energy), 20 May 2015.

[23] See for example, AER (2015), *Correcting errors in Ausgrid distribution determination 2015-16 to 2018-19*, Letter to Mr Vince Graham (Chief Executive Officer, Ausgrid), 20 May 2015.

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

TR_t is the total revenue allowable in year t

I_t is the sum of adjustments related to:

- the final carryover amount from the application of the DMIS from the 2010–15 distribution determination. This amount will be deducted from/added to allowed revenue in the 2016-17 pricing proposal
- the STPIS. This amount is deducted from/added to allowed revenues in regulatory year t based on the application of the S-factor

B_t is the sum of adjustments related to:

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

C_t is the sum of adjustments related to:

- feed-in tariff cost pass through amounts relating to 2013-14 and 2014-15
- amounts relating to the occurrence of any of the prescribed and nominated cost pass through events
- other one-off adjustments approved by the regulator in year t

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

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

This formula reflects the revenue cap formula contained in the Framework and Approach Paper, with the following adjustments:

- We have replaced the equal sign in the second total allowed revenue formula with a greater than or equal to sign (i.e. $TR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_{ij}^t q_{ij}^t$). This is because it is difficult for the expected revenue to be recovered from all customers via tariffs to exactly equal the revenue cap (e.g. due to rounding of rates or in circumstances where revenues (and prices) are required to be adjusted to satisfy side constraints).
- We have amended the formula component descriptions to reflect the positions set out in Section 6.5.1, and terminology used by the AER in its Preliminary Determination (where appropriate).

We have updated the following documents to reflect this formula:

- Chapter 4 of our Regulatory Proposal
- *04.01.00 – (Revised) Compliance with control mechanisms*
- *04.01.05 – (Revised) Control mechanism model.*

Other comments

If the AER chooses to apply the formula contained in the Preliminary Determination, corrected for the inclusion of ± $DUoS_t$ component at the end of the TAR_t formula (i.e. formula 3), then we consider the

AER should remove references in its decision to the revenue cap being TAR plus any DUOS unders and overs adjustment.

Further, if the S-factor remains in the AR_t calculation, then the description of AR_t should be revised. The annual smoothed expected revenue for 2015-16 is the smoothed revenue requirement for 2015-16 set out in the PTRM multiplied by $(1 + S_t)$.

Side constraints formula

Ergon Energy is generally comfortable with the approach taken by the AER in relation to the side constraints formula. However, due to changes we are proposing to the revenue cap formula, we consider the following amendments are required:

- the component $(1 + S_t)$ should be removed, as STPIS is covered by the I_t component. The description of the I_t component needs to be amended to reflect the revenue cap formula description above
- the component $DUoS_t$ should be removed, as the DUOS unders and overs adjustment is covered by the B_t component. The description of the B_t component needs to be amended to reflect the revenue cap formula description
- the description of the C_t component needs to be amended to include other one-off adjustments, as per the revenue cap formula description.

Proposed formula

The revised side constraints formula is:

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

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

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

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

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

ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1

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

I_t is the sum of adjustments related to:

- the final carryover amount from the application of the DMIS from the 2010–15 distribution determination. This amount will be deducted from/added to allowed revenue in the 2016-17 pricing proposal

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

B_t is the sum of adjustments related to:

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

C_t is the sum of adjustments related to:

- feed-in tariff cost pass through amounts relating to 2013-14 and 2014-15
- amounts relating to the occurrence of any of the prescribed and nominated cost pass through events
- other one-off adjustments approved by the regulator in regulatory year t.

We have updated Chapter 4 of our Regulatory Proposal to reflect this formula.

Other comments

If the AER decides to apply the side constraints formula set out in the Preliminary Determination (where the STPIS is included as a factor), we consider the following statement should be revised:

> "With the exception of CPI and X factors, the percentage for each of the other factors above can be calculated by dividing the incremental revenues (as used in the total annual revenue formula) for each factor by the expected revenues for regulatory year t–1 (based on the prices in year t–1 multiplied by the forecast quantities for year t)."[24]

Specifically, the AER should make reference to the STPIS factor after "CPI". This is because S_t is a factor not a revenue amount. It therefore cannot be calculated by dividing the incremental revenues by the expected revenues for regulatory year t-1.

6.6.5. DUOS unders and overs account

Ergon Energy accepts the AER's decision to apply a DUOS unders and overs account.

However, we note the example calculation of the DUOS unders and overs account set out in Table 14.1 of the Preliminary Determination does not reflect the AER's decision on the revenue cap formula. Rather, it reflects the example calculation provided in our October Regulatory Proposal which was based on the Framework and Approach revenue cap formula and our proposed application of the formula. For example, the table refers to the DUOS under/over adjustment approved by the regulator for year t-2 as being part of the B_t component.

If the AER does not accept the revenue cap formula set out in its own Framework and Approach Paper, then changes to the unders and overs account will be required. Further, the table heading incorrectly references "$000"; this should be "$'000".

[24] AER (2015), *Preliminary Decision, Ergon Energy determination 2015–16 to 2019–20, Attachment 14 – Control mechanisms*, April 2015, p18.

Finally, as noted above, if the AER does not apply tolerance limits, we believe the AER should include t-1 estimates in the DUOS unders and overs account. Our supporting documents, *04.01.00 – (Revised) Compliance with control mechanisms and 04.01.05 – (Revised) Control mechanism model,* provide an illustrative example.

6.6.6. TUOS unders and overs account

Ergon Energy accepts the AER's decision to apply a TUOS unders and overs. However, there are some inconsistencies in the example calculation of the TUOS unders and overs account set out in Table 14.2 of the Preliminary Determination. Specifically, the table heading incorrectly references "$000"; this should be "$'000". "Avoided TUOS Charges to EGs" has also been omitted under the transmission related payments section. Ergon Energy requests that the AER reinstate this line item consistent with the methodology for TUOS unders and overs approved in our 2015-16 Pricing Proposal.

As noted above, in the event that the AER confirms its decision not to apply tolerance limits, we propose to use a t-1 methodology for calculating DUOS unders and overs. If this methodology is agreed to be implemented for DUOS unders and overs, we propose that t-1 is also applied to designated pricing proposal charges to maintain consistency across the unders and overs account.

Our supporting document, *04.01.01 – (Revised) Designated Pricing Proposal Charges*, provides further information on this proposal. It also includes an example calculation.

6.6.7. Reporting on recovery of jurisdictional schemes

Ergon Energy accepts that a jurisdictional scheme unders and overs account should apply in our annual Pricing Proposal (as set out in Appendix C of Attachment 14 of the AER's Preliminary Determination). Consistent with the DUOS and TUOS unders and overs accounts, under or over recoveries of jurisdictional scheme amounts will affect prices two years after the under or over recovery was incurred. Given that Ergon Energy has not previously maintained a jurisdictional scheme unders and overs account, the first application of the account will occur in 2017-18, for jurisdictional scheme under or over recoveries from 2015-16.

However, as per the TUOS unders and overs calculation proposed by the AER, there is an inconsistency in the example calculation of the jurisdictional scheme unders and overs account set out in Appendix C of the Preliminary Determination. Specifically, the table heading incorrectly references "$000"; this should be "$'000".

As noted above, in the event that the AER confirms its decision not to apply tolerance limits, we propose to use a t-1 methodology for calculating jurisdictional scheme unders and overs, consistent with our approach for both DUOS and TUOS unders and overs.

6.6.8. Assigning retail customers to tariff classes

Ergon Energy supports many aspects of the AER's proposed procedures for assigning and reassigning retail customers to tariff classes as outlined in Appendix D of Attachment 14 of the Preliminary Determination. However, there are a few issues which we believe the AER needs to further consider. Our concerns are detailed below.

Notification

Ergon Energy seeks clarification from the AER regarding who we should notify when a tariff class assignment or reassignment is expected to occur. On page 14-26 of Attachment 14, the AER has indicated that distributors must inform customers of the availability of the dispute resolution mechanism under Part 10 of the NEL. However, this is inconsistent with the requirement to notify the customer's retailer of a tariff class assignment or reassignment (refer to section 6 of the procedures).

Ergon Energy considers that the notification should be sent to affected customers' retailers. This is consistent with the approach adopted in the Final Decision for New South Wales distributors. We consider that notifying retail customers imposes unnecessary costs on distributors and adds a level of confusion for our customers, given the final bill paid by a retail customer is dependent on the customer's retail contract and retail tariff selection with their chosen retailer. This is especially the case in Ergon Energy's distribution area where the majority of customers are on regulated retail tariffs that are largely based on Energex's network tariffs or do not reflect the underlying network tariff. We have responded to numerous queries over the regulatory control period 2010-15 in relation to this.

In the event the AER decides that Ergon Energy must notify the affected retail customer, we seek an exemption from notifying customers of a tariff class reassignment when such a change is set out in our Tariff Structure Statement (TSS).

The TSS was introduced as part of the November 2014 *Distribution Network Pricing Arrangements* rule change.[25] The statement will set out the network price structures and indicative price levels that will apply in a particular regulatory control period. Ergon Energy's initial TSS is due on 27 November 2015.[26]

Given the rule change was finalised after our initial Regulatory Proposal, Ergon Energy did not have the opportunity to consider the interaction of the TSS and the procedures for assigning and re-assigning retail customers to tariff classes.

Ergon Energy expects to engage with customers and other interested stakeholders on the structure of our existing tariff classes as part of our TSS development. In particular, we are likely to seek feedback on whether our tariff classes for Standard Control Services should be consolidated.

If we are required to notify each affected retail customer, this would impose significant costs and administrative burden on Ergon Energy, without providing any real benefit to customers. This is because any consolidation will not affect the customer's underlying network tariff or the network charges they will pay. Further, customers will have visibility of the change, in advance, through our TSS.

Consequently, if we are required to notify each affected retail customer, Ergon Energy proposes several changes to the procedures. These changes are set out in Table 6.

[25] AEMC (2014), *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements Rule 2014,* 27 November 2014.

[26] NER, clause 11.73.2. Normally, the TSS would be submitted as part of a DNSP's regulatory proposal. The AER would then assess it at the same time as the regulatory proposal. Transitional arrangements were introduced for the initial TSS due to the timing of the rule change process and the significant work required to be undertaken in order to apply the new pricing principles to develop network tariffs.

Table 6: Proposed changes to the procedures for assigning and reassigning retail customer to tariff classes – Tariff Structure Statement exemption

Section	Type of change	Change
Reassignment of existing retail customers to another existing or a new tariff during the next regulatory control period	Insert new paragraph	6. Ergon Energy may reassign a retail customer to a new tariff class if the retail customer's existing tariff class becomes obsolete in accordance with Ergon Energy's Tariff Structure Statement. In determining the tariff class to which the retail customer will be reassigned, Ergon Energy must take into account the factors set out in paragraphs 3 and 4 above.
Objections to proposed assignments and reassignments	Modify existing clause	7. Ergon Energy must notify […]. This clause does not apply if the reassignment occurred as a result of paragraph 6 above and the retail customer's underlying network tariff remains the same.
Paragraphs 6 to 12 (existing)	Modify existing clauses	Update numbering of all paragraphs after paragraph 6 (existing) and all paragraph number references, as appropriate

Ombudsman powers

Ergon Energy considers that the investigation of disputes in relation to tariff class assignments would fall outside the Queensland Energy and Water Ombudsman's current functions and would not be an eligible matter that could be referred to the Ombudsman under the *Energy and Water Ombudsman Act 2006 (Qld)*. This is because distribution pricing and associated processes (such as the allocation of customers to tariff classes) is not a function or obligation under an eligible energy Act (i.e. the *Electricity Act 1994* or *Gas Supply Act 2003*) which in Queensland governs the Ombudsman's delegated authority and ability to investigate a matter or dispute. Rather, Ergon Energy's distribution pricing and our assignment of customers to tariff classes reflects an obligation under the NER and the AER's Distribution Determination.

Further, the Energy and Water Ombudsman Act explicitly provides that a dispute cannot be referred to the Energy and Water Ombudsman if the dispute can be dealt with under the *Electricity—National Scheme (Queensland) Act 1997*. This Act provides that the NEL applies as a law in Queensland, and incorporates the NEL as an attachment. As affected retailers are entitled to seek resolution via the dispute resolution process available under Part 10 of the NEL (in accordance with draft section 7c of Appendix D of the AER's Preliminary Determination), this further supports the position that an objection to a tariff class is not an eligible matter that is able to be referred to the Energy and Water Ombudsman in Queensland.

Therefore, as tariff class objections are not within the Queensland Energy and Water Ombudsman jurisdictional powers, in the event an objection is unable to be resolved to the satisfaction of the retailer by Ergon Energy, the only external escalation point will be the AER, via the dispute resolution processes available under part 10 of the NEL.

Adjustments to prices if objection is upheld

Paragraph 10 of the AER's procedures require Ergon Energy to make adjustments to prices as part of the next annual review of prices, in the event that a customer's objection to a tariff assignment or reassignment is upheld by an external dispute resolution body.

Ergon Energy interprets this to mean:

- The change to the tariff class and correction of the associated underlying tariff would be effective from the date of decision from the external dispute resolution body (the AER).

- In the interim (i.e. between the date of effect and the next pricing year) the customer would continue to be assigned to the tariff class to which we had assigned or reassigned them to and continue to be charged on the associated underlying tariff.
- The tariff class reassignment and backdating (or addition) of any charges would be carried out in the next pricing year from the effective date.

While Ergon Energy agrees that customers have the right to any overpayments that may have occurred, we do not believe it is appropriate to do this as part of an annual review process. Rather, any adjustment should be made at the time of the next network bill after the date of effect. Ergon Energy considers this approach is preferable as:

- it is advantageous for customers. Specifically, if the upheld decision is financially favourable to the customer, then the customer will be charged the associated underlying tariff sooner. This minimises their exposure to unnecessarily higher network bills, which the customer may find difficult to pay. It also means the customer will receive any refund associated with the past overpayments sooner
- it is consistent with the approach we have taken to objections upheld under our own internal review process. We do not consider that a different process should apply, just because the decision to assign or reassign the customer is a result of an outcome from an external dispute resolution process
- there are market settlement issues. Specifically, the market timeframe for retrospectively applying changes to Network Tariff Codes (which are associated with the tariff class) is 140 business days.[27] Any adjustments outside of this timeframe would require off market settlement. Our internal billing system has also been developed to reflect the retrospectivity rules determined by AEMO.

Therefore, Ergon Energy considers “annual review of prices” should be replaced with “next network bill”.

Alternative Control Services

Ergon Energy is concerned by the requirement to provide written notification to retailers for each tariff class assignment or reassignment for Alternative Control Services. While we recognise the AER must develop procedures for Alternative Control Services,[28] we note there is no requirement to provide such a notice under the NER. Further, we consider the AER has discretion to apply different processes for Alternative Control Services and Standard Control Services to cater for the differences between these two types of services.

We believe it is not practical to provide written notification to retailers for each tariff class assignment or reassignment. Customers or retailers essentially assign themselves to a tariff class by selecting the service they require. Further, the tariff classes and objection procedures are set out in our Retailer Handbook, which is an operational handbook that sets out the interactions between Ergon Energy and retailers operating in our distribution area.

In light of the above, Ergon Energy proposes a number of changes. These changes are set out in Table 7.

[27] Refer to section 21.5(a) of the Australian Energy Market Operator’s (AEMO) *Market Settlement and Transfer Solution Procedures: The Consumer Administration Transfer Solution Procedure Principles and Obligations* (version 4.1).
[28] NER, clause 6.18.3.

Table 7: Proposed changes to the procedures for assigning and reassigning retail customer to tariff classes – Alternative Control Services

Section	Type of change	Change
Objections to proposed assignments and reassignments	Modify existing heading	Objections to proposed assignments and reassignments for Standard Control Services
Not applicable	Insert new heading after existing paragraph 11	Objections to proposed assignments and reassignments for Alternative Control Services
Objections to proposed assignments and reassignments for Alternative Control Services	Insert new paragraph	12. Ergon Energy must make available information on tariff classes and the dispute resolution procedures referred to in paragraphs 7 b and 7 c above to retailers operating in its distribution area.
Objections to proposed assignments and reassignments for Alternative Control Services	Insert new paragraph	13. If Ergon Energy receives a request for further information from a customer's retailer in relation to a tariff class assignment or reassignment, then it must provide such information within a reasonable timeframe. If Ergon Energy reasonably claims confidentiality over any of the information requested by the customer's retailer, then it is not required to provide that information to the customer's retailer. If the customer's retailer disagrees with such confidentiality claims, he or she may have resort to the dispute resolution procedures referred to in paragraph 7 b and 7 c above.
Objections to proposed assignments and reassignments for Alternative Control Services	Insert new paragraph	14. If a customer's retailer makes an objection to Ergon Energy about a tariff class assignment or reassignment, Ergon Energy must reconsider the assignment or reassignment. In doing so Ergon Energy must take into consideration the factors in paragraphs 3 and 4 above, and notify the customer's retailer in writing of its decision and the reasons for that decision.
Objections to proposed assignments and reassignments for Alternative Control Services	Insert new paragraph	15. If a customer's retailer's objection to a tariff class assignment or reassignment is upheld by the relevant body in paragraph 7 b and c above, then any adjustment which needs to be made to tariffs will be done by Ergon Energy as part of the next network bill.
Paragraph 12 (existing)	Modify existing paragraphs	Update numbering of paragraph 10 (existing) to paragraph 16.

Drafting errors

Ergon Energy has identified a number of drafting errors in the procedures.

The AER has incorrectly applied the term "customer's retailer" in section 6 of the procedures. This section states:

> "Ergon Energy must notify a customer's retailer in writing of the tariff class to which the **customer's retailer** has been assigned or reassigned, prior to the assignment or reassignment occurring." [emphasis added]

The second reference to “customer’s retailer” (in bold text) should refer to “retail customer”.

The AER should also review the wording of section 7 b of the procedures. Notwithstanding our comments above regarding the ability to apply to the Queensland Energy and Water Ombudsman in the event of dispute, we note that ombudsman scheme is only available to small retail customers; not customer’s retailers. Therefore, this section should not reference “customer’s retailers”.

Finally, we consider the heading “Reassignment of existing retail customers to another existing or a new tariff during the next regulatory control period” should refer to “tariff class” instead of “tariff”, since this section relates to tariff classes.

6.6.9. Other comments

On page 14-7 of Attachment 14, the AER has incorrectly indicated that the control mechanism is contained in Appendix A. Ergon Energy notes that this appendix contains the DUOS unders and overs account.

Supporting documents

The following documents support our response to the AER on SCS Building Blocks, Control Mechanism and Pricing:

Name
Houston Kemp – Analysis of Different Approaches to Calculating Remaining Lives (File name: Houston Kemp – Depreciation report)

Definitions, acronyms, and abbreviations

ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARR	Annual Revenue Requirement
CCP	Consumer Challenge Panel
CPI	Consumer Price Index
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DUOS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme
FiT	Feed-in tariff
NEL	National Electricity Law
NER	National Electricity Rules
NPV	Net Present Value
NSP	Network Service Provider
NSW	New South Wales
PTRM	Post Tax Revenue Model
RAB	Regulatory Asset Base
RFM	Roll Forward Model
TAB	Tax asset base
TAR	Total Annual Revenue
TSS	Tariff Structure Statement
TUOS	Transmission Use of System
STPIS	Service Target Performance Incentive Scheme
WACC	Weighted Average Cost of Capital
WARL	Weighted Average Remaining Life