Chapter 3: Revenue building blocks for Standard Control Services

Introduction and summary of changes

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

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

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

Customer benefits

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

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

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

3. Revenue building blocks for Standard Control Services

3.1 Background

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

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

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

These building blocks, added together, allow the AER to determine the Annual Revenue Requirement (ARR) for each regulatory year.[38]

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

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

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

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

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

[38] NER, clause 6.4.3.

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

[40] Refer to *03.01.04 – Post Tax Revenue Model (January 2015)*.

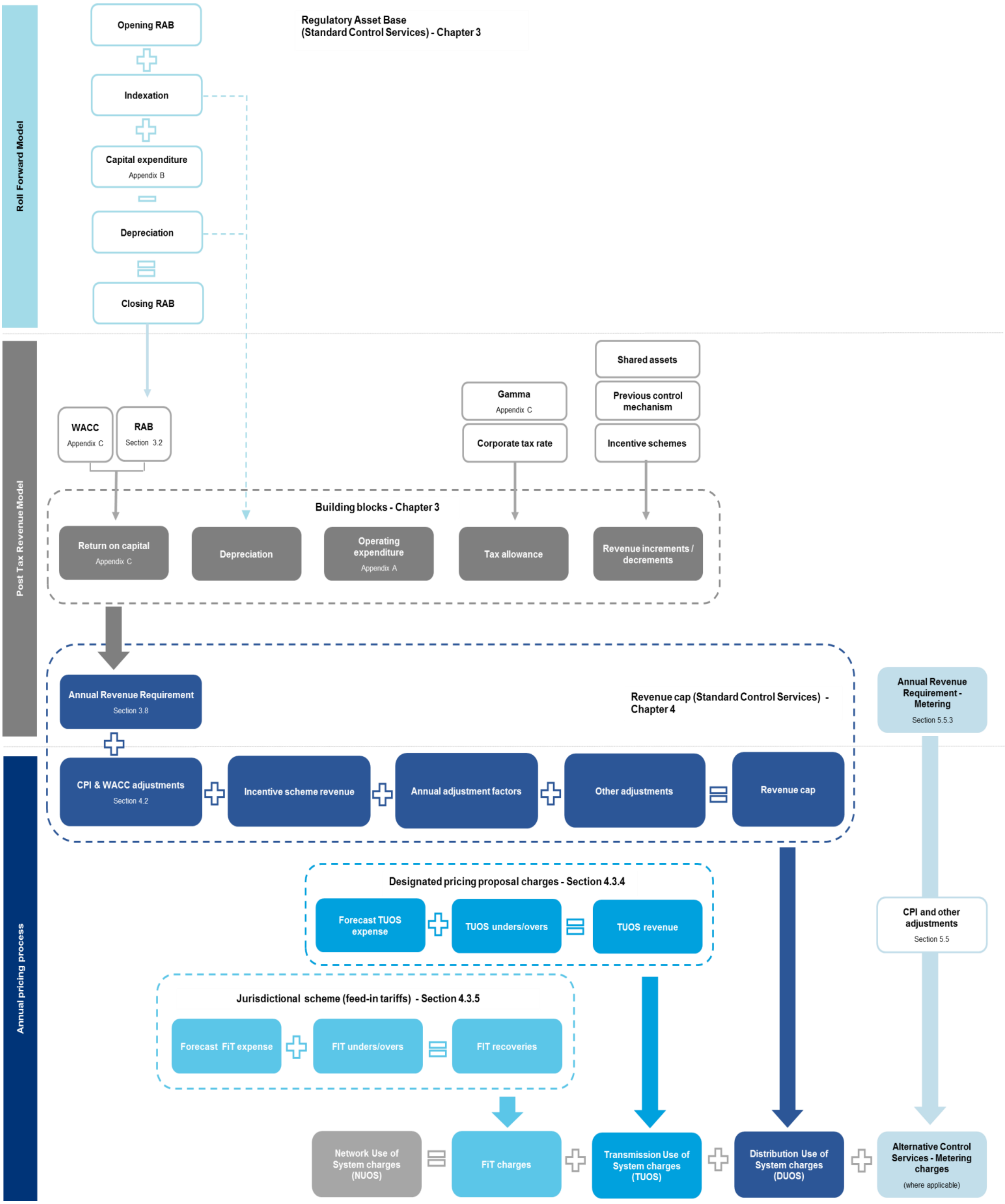

Figure 5: Components of the network bill and this Regulatory Proposal

3.2 Regulatory Asset Base

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

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

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

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

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

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

3.2.1 Establishing the RAB

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

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

[41] NER, clause 11.16.3.

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

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

3.2.2 Capital Contributions

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

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

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

As illustrated in the diagram, the capital contributions are not removed from the RAB as doing so would result in the NPV of the revenue stream from those assets being lower than the original value of the contributions (i.e. the original revenue adjustment would have been too high). Therefore, the value of the actual capital contributions for the regulatory control period 2010-15 have been included in the roll forward of the RAB to 1 July 2015, so that the forward revenue calculations will continue to include an amount for the return on, and of, the past capital contributions.

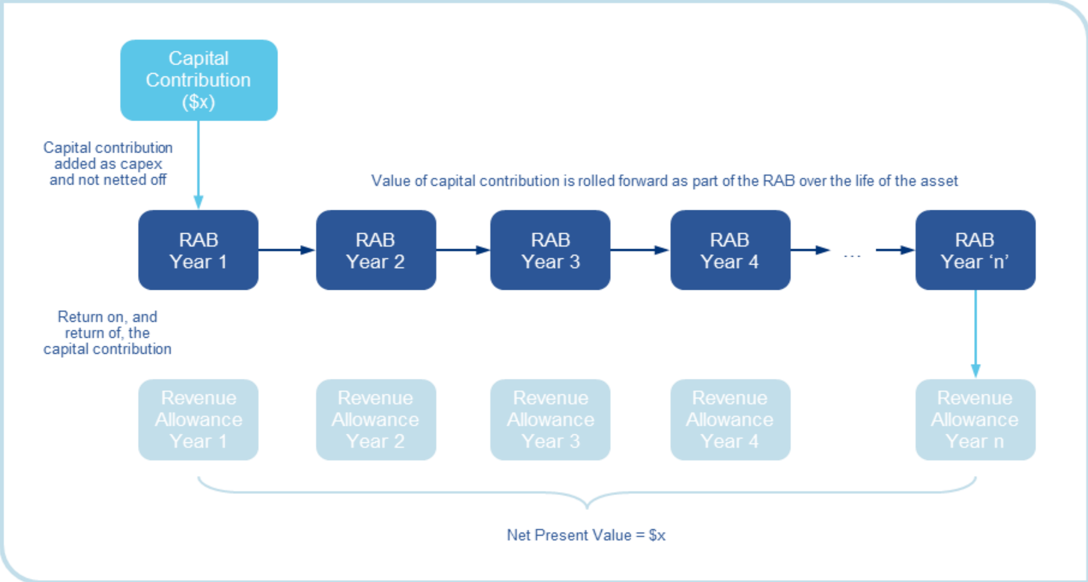

Figure 6: Treatment of capital contributions under Chapter 11 of the NER

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

3.2.3 Roll forward of the RAB

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

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

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

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

3.2.4 Adjustments to the RAB

Ergon Energy has made adjustments for the following reasons:

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

Each of these adjustments are summarised briefly below.

Removal of assets due to disposals

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

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

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

Removal of assets due to service reclassifications

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

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

3.3 Return on capital

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

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

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

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

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

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

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

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

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

3.4 Return of capital (depreciation)

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

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

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

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

[42] NER, clause 6.5.2(c).

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

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

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

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

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

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

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

3.5 Operating expenditure

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

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

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

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

Table 7: Proposed operating expenditure, 2015-20

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

3.6 Corporate income tax

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

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

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

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

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

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

3.7 Revenue increments/decrements

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

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

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

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

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

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

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

3.7.1 Carry forward of DUOS unders and overs

Under a revenue cap, our revenues are adjusted annually to clear any under or over recovery of actual revenue collected through DUOS charges. This 'unders and overs' process is undertaken as part of annual pricing and ensures that we recover no more and no less than the Maximum Allowable Revenue[47] approved by the AER for any given year.

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

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

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

3.7.2 Incentive schemes

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

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

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

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

[46] NER, clause 6.4.3(a)(6A).

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

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

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

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

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

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

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

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

3.7.3 Shared assets

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

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

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

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

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

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

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

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

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

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

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

3.8 Annual Revenue Requirement

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

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

Table 11: Annual Revenue Requirement, 2015-20

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

3.9 X-factors

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3.10 Applying 2015-20 incentive schemes

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

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

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

- DMIS
- STPIS
- CESS.

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

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

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

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

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

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

3.11 Supporting documentation

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

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