



FINAL DECISION

Ergon Energy determination

2015–16 to 2019–20

Overview

October 2015

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Note

This overview forms part of the AER's final decision on Ergon Energy's 2015–20 distribution determination. It should be read with all other parts of the final decision.

The final decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Demand management incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanism

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model

Shortened form	Extended form
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

Revocation and substitution of preliminary decision

In November 2012, the Australian Energy Market Commission (AEMC) introduced major changes to the economic regulation of electricity distributors under chapter 6 of the National Electricity Rules (NER).¹

To allow consumers to receive the benefit of the new rules the AEMC made transitional rules under chapter 11 of the NER. In accordance with those transitional rules, we:²

- made a preliminary determination for the 2015–20 regulatory control period on 29 April 2015. This preliminary determination formed the basis for approving prices for Ergon Energy's customers from 1 July 2015 to 30 June 2016.
- now revoke that preliminary determination and substitute it with a new distribution determination which takes effect at the date it is made and applies in respect of the 2015–20 regulatory control period (referred to as our final decision). The new distribution determination provides for adjustments over the regulatory control period to account for differences between the revenue that we approved for the 2015–16 regulatory year in the preliminary determination and in the final decision.³

¹ AEMC, *Final Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012.

² NER, cl. 11.60.4.

³ NER, cl. 11.60.4(d) and (e).

1 Introduction

The Australian Energy Regulator (AER) is responsible for the economic regulation of electricity transmission and distribution systems in Australia, except for Western Australia. Ergon Energy is one of two distribution network service providers (distributors) in Queensland and is responsible for providing electricity distribution services outside of south east Queensland to the far north and western areas of Queensland. We regulate the revenue Ergon Energy and other distributors can recover from their customers.

The National Electricity Law (NEL) and National Electricity Rules (NER) provide the regulatory framework governing electricity networks. The National Electricity Objective (NEO), as set out in the NEL, is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—

- price, quality, safety, reliability and security of supply of electricity; and
- the reliability, safety and security of the national electricity system.⁴

Ergon Energy was required to submit a regulatory proposal to us for approval.⁵ The central component of a regulatory proposal is the amount of revenue Ergon Energy proposes to recover from consumers over the 2015–20 regulatory control period.⁶ We assess Ergon Energy's proposal, using the NER's detailed rules including a 'building block model' to determine how much revenue a distributor requires to cover its efficient costs. We must decide whether to accept Ergon Energy's regulatory proposal. If we do not accept that Ergon Energy's proposal complies with the requirements of the NER, we must substitute an alternative amount of revenue that we are satisfied does comply. We must undertake this assessment and make this decision in a matter that will or is likely to contribute to the achievement of the NEO. Where there are two or more possible decisions that will do so, make a decision that we are satisfied will contribute to the NEO to the greatest degree.

The NER sets out an incentive regulation regime to guide our decision on a distributor's revenue.⁷ Incentive regulation encourages distributors to spend efficiently and to share the benefits of efficiency gains with consumers.⁸

⁴ NEL, s. 7.

⁵ NER, cl. 6.8.2.

⁶ NER, cll. 6.3.1 and 6.8.2.

⁷ NER, cl. 6.2.6(a) states that for standard control services, the control mechanism must be of the prospective CPI minus X form, or some incentive-based variant of the prospective CPI minus X form, in accordance with Part C (Building Block Determinations for standard control services). Further revenue and pricing principles (RPPs) state a regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides.

⁸ AEMC, *Consultation paper: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, February 2015 p. 3.

Under this incentive regime, the revenue allowance we determine does not set Ergon Energy's actual operating budget. It is up to Ergon Energy to decide how best to use this revenue allowance in providing distribution services and complying with its obligations. To determine the revenue allowance, we assess and determine forecast expenditure required by Ergon Energy, acting as a prudent operator, incurring efficient costs in delivering safe and reliable distribution services. The regime works to provide Ergon Energy with incentives to outperform those forecasts, while delivering safe, reliable and secure services to its customers. In other words, a prudent operator is expected to respond to the incentives for distributors to innovate and invest in responses to changes in consumer needs and productive opportunities.⁹ This is consistent with the NEO.

Ergon Energy submitted its initial regulatory proposal for the 2015–20 regulatory control period in October 2014. In April 2015, we published our distribution determination (referred to as our preliminary decision), which took effect on 1 July 2015. At the same time as we published our preliminary decision, we invited submissions on the revocation and substitution of that determination. Ergon Energy submitted a revised proposal in July 2015. This final decision replaces the preliminary decision and is based on consultation and submissions from various stakeholders on Ergon Energy's initial and revised proposals as well as our preliminary decision.

In accordance with the transitional rules, we revoke our preliminary decision. This overview, together with its attachments, constitutes our final decision on the making of a new distribution determination in substitution for that preliminary decision, in response to Ergon Energy's revised regulatory proposal. This overview provides a summary of our final decision and its constituent components. It sets out the issues we covered, the conclusions we made, and how those conclusions were reached. We also explain why we are satisfied our decision contributes to the achievement of the NEO to the greatest degree. In our attachments we set out detailed analysis of the constituent components that make up Ergon Energy's revised proposal and our decision on each of them. Appendix A contains the full list of constituent components for our final decision.

⁹ Hansard, *SA House of Assembly*, 9 February 2005, p. 1452.

2 Decision

Our final decision is that Ergon Energy can recover \$6295.4 million (\$ nominal) from consumers over the 2015–20 regulatory control period.¹⁰ Our total revenue allowance is 23.6 per cent less than Ergon Energy's initial regulatory proposal and 19.3 per cent less than its revised regulatory proposal of \$7798.2 million (\$ nominal) for the 2015–20 regulatory control period.

Our final decisions provides for \$216.3 million (\$ nominal) more in allowed revenue over the 2015–20 regulatory control period than our preliminary decision set out. The reasons we depart from our preliminary decision are set out in this overview and subsequent attachment.

This decision represents a turning point for electricity prices in Queensland that have increased consistently since 2004 up until recently. Over this period retail electricity prices rose dramatically,¹¹ due largely to the rising cost of investing in and operating electricity networks in Queensland.¹² For a decade the drivers of high network costs included stringent reliability standards, steadily rising peak demand, population growth and rising costs of finance. These factors are no longer significant drivers of increasing network costs in Queensland as discussed in this decision.

Over the 2015–20 regulatory control period the annual revenue to be recovered by Ergon Energy from customers will fall each year in real terms. To a large extent, the key driver of this outcome is lower financing costs expected over the next five years compared with the rate of return we set in our 2010 decision that was at a time of market uncertainty due to the global financial crisis. Other factors contributing to our decision to set a lower total revenue allowance than Ergon Energy proposed include Ergon Energy's efforts to improve its operating efficiency and a reduced need for capital expenditure (capex) following changes in reliability standards. We discuss each of these factors in more detail in this final decision.

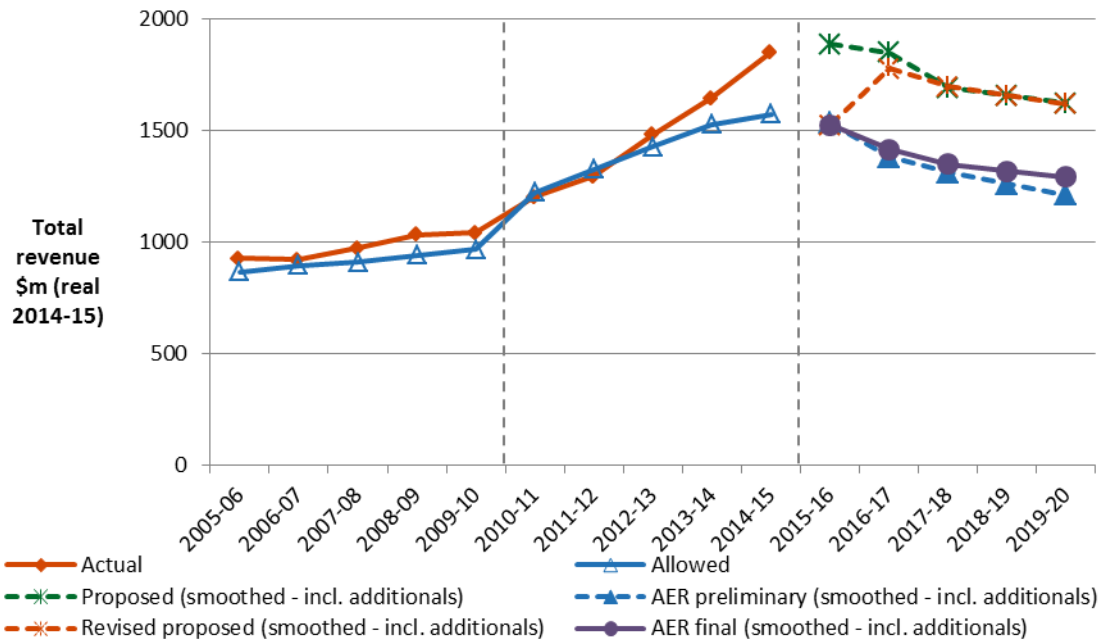
Figure 1 illustrates our decision on allowable revenue. The total revenue we have approved enables Ergon Energy to meet the efficient costs of operating and maintaining a safe and reliable network. Also shown in figure 1 are the revenues Ergon Energy proposed in its initial and revised regulatory proposals. The total revenue allowance takes account of additional amounts that Ergon Energy is able to recover from network customers, such as costs that stem from the Queensland Solar Bonus Scheme.

¹⁰ This amount excludes other additional factors that will be recovered as part of DUoS but not within the building block revenue, such as the Solar Bonus Scheme feed-in tariff (FiT). The total expected revenue including the additional is \$7399.7 million.

¹¹ Interdepartmental committee on electricity sector reform, *Terms of Reference*, 2012, p. 1. See https://www.dews.qld.gov.au/_data/assets/pdf_file/0013/30622/IDC-terms-of-reference.pdf.

¹² Queensland Productivity Commission, *Issues paper, Electricity Pricing in Queensland*, October 2015, pp. 6–9.

Figure 2 Ergon Energy's past total revenue, proposed total revenue and AER total revenue allowance – including additional (\$ million, 2014–15)

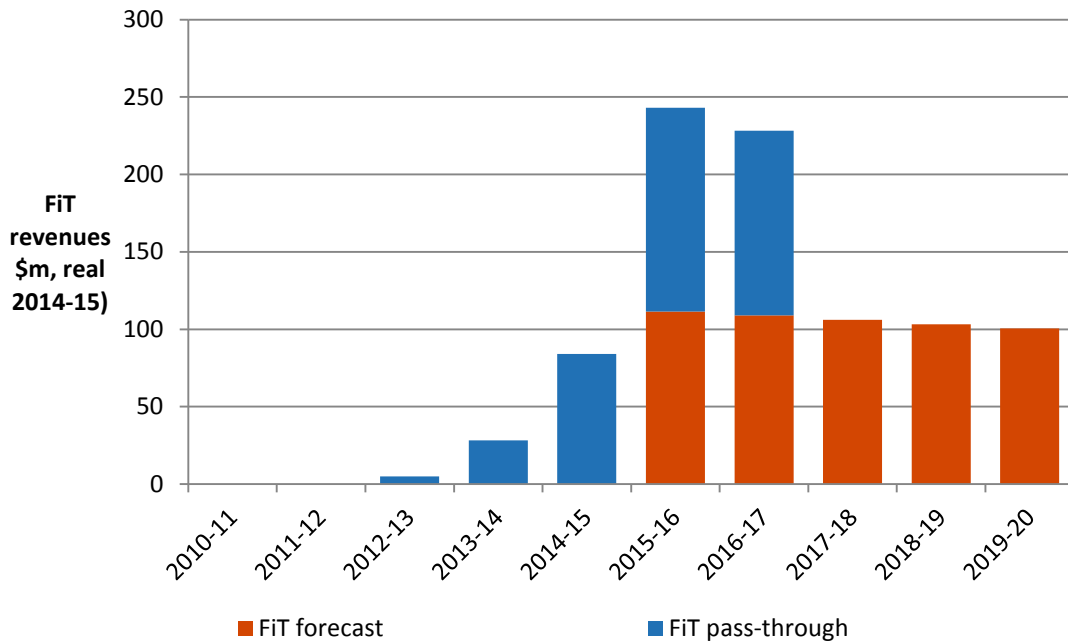


Source: AER analysis.

Note: 'Additional' in DUoS include Solar Bonus Scheme forecasts (jurisdictional scheme obligation for FiT) for 2015–20, estimated Solar Bonus Scheme pass throughs for 2015–16 and 2016–17 relating to under-recoveries in 2013–14 and 2014–15, estimated DUoS under recovery for 2013–14, transitional capital contribution and shared assets under/over recovery from 2010–15, STPIS allowance from 2010–15 and DMIA over recovery from 2010–15. This is discussed further in attachment 1, annual revenue requirement. The 'Allowed' 2014–15 data point is the amount allowed in the AER final decision excluding additional. The 'Actual' 2014–15 data point is an updated forecast of the amount Ergon Energy actually expects to recover, including additional, as submitted in its reset RIN.

The Solar Bonus Scheme will add an expected \$831.2 million (\$ nominal) to Ergon Energy's approved revenue over the 2015–20 regulatory control period. Neither Ergon Energy nor the AER are able to influence the costs that Ergon Energy incurs under this scheme. While the Solar Bonus Scheme is now closed, costs associated with the feed in tariffs (FiT) available under the scheme increased sharply between 2010 and 2015 and will diminish slowly over time. The rapid growth of solar PV installations in Ergon Energy's distribution area and the revenue raised by Ergon Energy to fund the Solar Bonus Scheme over the 2015–20 are shown in figure 2. Figure 2 shows the FiT passed through to Ergon Energy customers in the 2010–15 regulatory period as well as the forecast FiT for the 2015–20 regulatory control period.

Figure 2 Ergon Energy's feed in tariff revenues (\$ million, 2014–15)

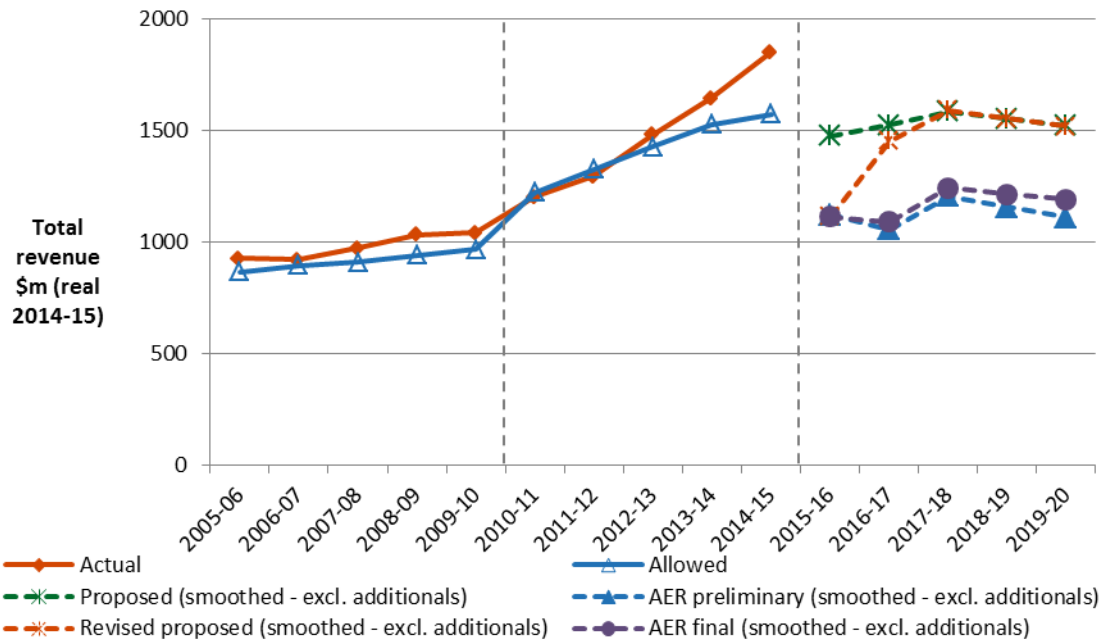


Source: AER analysis.

Note: The overlap in forecast and pass through of FIT payments in 2015–16 and 2016–17 reflects the shift from a true-up approach conducted with a 2 years lag applying to the 2010–15 regulatory control period to a forecast approach where costs are recovered in the years they are incurred for the 2015–20 regulatory control period.

If the revenue needed to meet the cost of the Solar Bonus Scheme is put aside, the revenue requirement for Ergon Energy's distribution network can be shown more clearly. Figure 3 (below) shows our final decision compared with Ergon Energy's initial and revised proposals excluding the additional such as the Solar Bonus Scheme and other revenue adjustments carried forward from the 2010–15 regulatory control period. Figure 3 also shows the revenue we approved in our final and preliminary decisions are similar, with the key difference being a slightly higher allowance for opex.

Figure 3 Ergon Energy's past total revenue, proposed total revenue and AER total revenue allowance – excluding additional (\$ million, 2014–15)



Source: AER analysis.

Figure 3 shows that, after accounting for the Solar Bonus Scheme, the underlying revenue requirement from 2015–16 onwards is lower than in the recent past. However, it is also clear there are differences between the revenue Ergon Energy is seeking and what we have approved in this final decision.

We determine the revenue Ergon Energy is to recover from customers by examining the costs we expect it to incur as an efficient and prudent service provider. In assessing Ergon Energy's revised proposal, we have identified the following factors that we see impacting on Ergon Energy's costs in the 2015–20 regulatory control period:

- An improved investment environment compared to our 2010 decision, which translates to lower financing costs necessary to attract efficient investment. In our 2010 final decision we approved a rate of return of 9.72 per cent.¹³ This compares with the approved rate of return in this final decision of 6.01 per cent.
- Forecast average demand, which is expected to remain reasonably flat over the 2015–20 regulatory control period. Maximum demand is forecast to grow by around 1 per cent over the 5 years.¹⁴ This means Ergon Energy is under less pressure to

¹³ AER, *Final decision. Queensland distribution determination 2010–11 to 2014–15*, May 2010, p. 267. This figure is nominal vanilla.

¹⁴ Forecast changes in maximum demand are not uniform across the network. Some areas are expected to see stronger maximum demand growth and others stable or declining maximum demand.

expand its network than in the 2010–15 regulatory control period to meet the needs of additional customers or any increased demand from existing customers. Ergon Energy has reflected weaker demand into its forecast augmentation expenditure, which we have accepted. We discuss this in attachment 6.

- A reduction in capex in response to the recommendations from the Queensland Electricity Network Capital Program Review 2011. Specifically, the independent panel recommended that alternatives were now available which allowed for more efficient capital investment that better reflected the needs of customers in the current economic climate while still achieving the level of security envisaged.¹⁵ The effect of these changes became evident throughout the 2010–15 regulatory control period, particularly from 2012.¹⁶ Further detail is provided in attachment 6.
- Changes to the Queensland Government's reliability standards. From 1 July 2014 the reliability standards, amongst other things, reduced the need to build new infrastructure for reliability purposes.¹⁷
- Improvements in efficiency in how Ergon Energy operates its business. In May 2012, the Queensland Government initiated the Interdepartmental Committee on Electricity Sector Reform (IDC).¹⁸ The IDC appointed a network-specific Independent Review Panel (IRP). The IRP recommended that efficiencies could be achieved. In response to this report, Ergon Energy identified some efficiencies and these are reflected in its regulatory proposal.¹⁹ We have not accepted Ergon Energy's overall forecast opex. Following an assessment of Ergon Energy's revised base year operating expenditure (opex), including an adjustment to remove metering costs that Ergon Energy had incorrectly included in its networks services opex, we have not found material inefficiency in Ergon Energy's revealed expenditure. For this reason we have accepted Ergon Energy's base year opex as a starting point for its forecast opex. However we expect Ergon Energy will identify further efficiencies in the 2015–20 regulatory control period and will review this closely during the 2020 distribution determination. Section 3.6 of this overview and attachment 7 provide further discussion of Ergon Energy's operating costs

These factors are reflected throughout our final decision and impact the different constituent components of our decision to varying degrees.

The component of our decision that drives most of the difference between our final decision and Ergon Energy's revised proposal is the allowed rate of return. A further aspect is the provision made for imputation credits (gamma), which forms part of the

¹⁵ Electricity Network Capital Program Review 2011, Detailed report of the Independent Panel, 2011, p. 10. See: https://www.business.qld.gov.au/__data/assets/pdf_file/0018/9117/ENCAP_Review_Final_Report_3_new.pdf.

¹⁶ AER, *Issues paper, Queensland electricity distribution determination 2015–16 to 2019–20*, December 2014, p. 13; Energex, *Regulatory proposal*, October 2014, pp. 1, 4, 23.

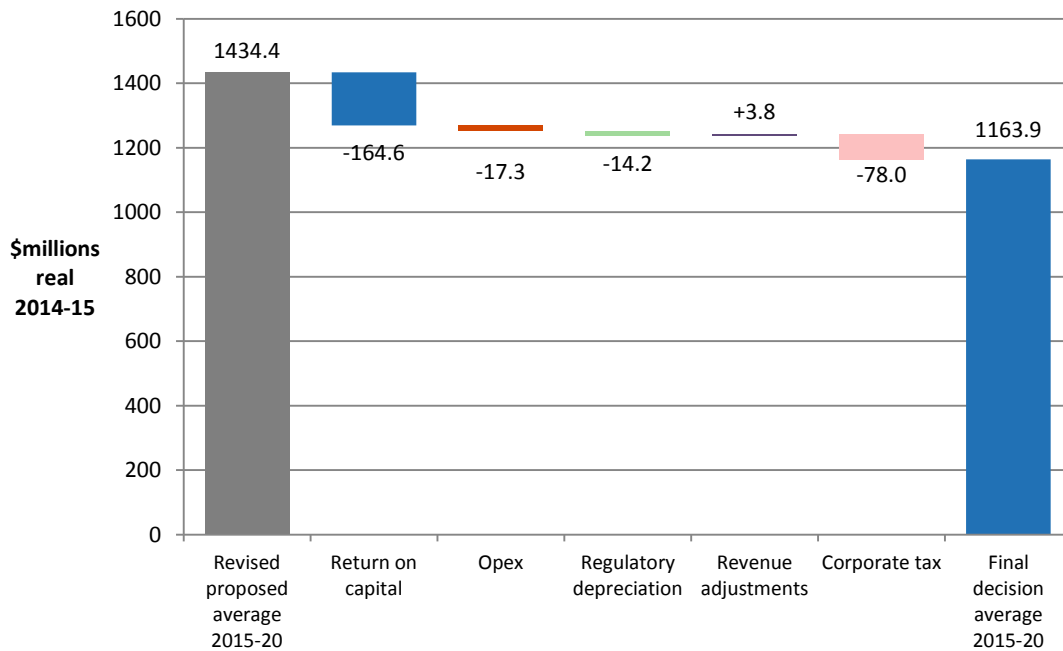
¹⁷ DEWS, *Changes to electricity network reliability standards*; Refer to <https://www.dews.qld.gov.au/policies-initiatives/electricity-sector-reform/supply/electricity-network-reliability-standards>.

¹⁸ Interdepartmental committee on electricity sector reform, *Report to government*, May 2013.

¹⁹ AER, *Preliminary decision Energex, Attachment 7, Operating expenditure*, April 2015, pp. 7-133 and 7-134.

corporate tax allowance. Changes to the allowed rate of return also flow on to impact the corporate tax allowance (in addition to gamma) given the reduction in overall revenue requirements. Attachment 4 discusses this interrelationship in detail. Figure 4 illustrates the constituent components of our final decision (which the NER refers to as building blocks).

Figure 4 AER's final decision and Ergon Energy's revised proposed annual building block costs (\$ million 2014–15)



Source: AER analysis.

We conclude that Ergon Energy has proposed to recover more revenue from its customers than is necessary for the safe and reliable operation of its network. It follows that we consider that Ergon Energy's proposal does not contribute to the NEO to the greatest degree. We come to these views as a result of the detailed analysis for each constituent component of our final decision.

2.1 Impact of decision

Our bill impact calculations adopt the network charges in our final decision for Energex. This is because retail electricity prices in Ergon Energy's distribution area are determined under the Queensland Government's uniform tariff policy. The policy results in regulated retail electricity prices in Ergon Energy's distribution area being matched to those in Energex's area.

We expect a typical residential final bill to reduce by between 1–2 per cent per annum over the 2015–20 regulatory control period. We expect bills to remain below the average annual residential customer bill paid in 2014–15. Distribution charges—for standard control services—represent approximately 42 per cent, on average, of the annual electricity bill for Energex customers. Other factors may affect a customer's

electricity bill, such as their consumption, their specific tariff, the wholesale price of electricity or changes in the retail margin.

Table 1 shows the estimated impact of our final decision on the average residential and small business customers' annual electricity bills in Energex's network area over the 2015–20 regulatory control period, compared with Energex's revised proposal.

Table 1 AER's estimated impact of its final decision on the average residential and small business customers' electricity bills in Energex's network area for the 2015–20 period (\$ nominal)^a

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
AER final decision						
Residential annual bill ^a	1470	1445	1428	1406	1389	1375
Annual change ^c		–25 (–1.7%)	–17 (–1.2%)	–21 (–1.5%)	–17 (–1.2%)	–14 (–1.0%)
Small business annual bill ^b	3036	2985	2949	2905	2869	2839
Annual change ^c		–51 (–1.7%)	–36 (–1.2%)	–44 (–1.5%)	–36 (–1.2%)	–30 (–1.0%)
Energex revised proposal						
Residential annual bill ^a	1470	1445	1473	1496	1518	1539
Annual change ^c		–25 (–1.7%)	28 (1.9%)	23 (1.6%)	23 (1.5%)	21 (1.4%)
Small business annual bill ^b	3036	2985	3042	3089	3136	3178
Annual change ^c		–51 (–1.7%)	57 (1.9%)	47 (1.6%)	47 (1.5%)	43 (1.4%)

Source: AER analysis; Energy Made Easy, www.energymadeeasy.gov.au; QCA, *Final determination, Regulated retail electricity prices 2014–15*, May 2014, p. 4.

- (a) Based on the annual bill for a typical consumption of 4100 kWh per year during the period 1 July 2014 to 30 June 2015.
- (b) Based on the annual bill for a typical consumption of 10000 kWh per year during the period 1 July 2014 to 30 June 2015.
- (c) Annual change amounts and percentages are indicative. They are derived by varying 2014–15 bill amounts in proportion with total annual regulated revenue divided by forecast demand. Actual bill impacts will vary depending on electricity consumption, tariff class and other variables.

The figures presented above include a number of additional revenues such as the Queensland Solar Bonus Scheme FiT— that Energex will recover over the 2015–20 regulatory control period. Similar additional revenues are recovered by Ergon Energy, although the magnitude differs to some degree.

2.2 Key issues raised in revised proposal

In its revised proposal, Ergon Energy raised a number of concerns with our preliminary decision. Substantive concerns included:

- Rate of return — Ergon Energy remains concerned by our approach to estimating the expected return on equity. Ergon Energy submitted that our approach does not

take into account all relevant evidence and give such evidence a direct role in the estimation process.²⁰

- Role of benchmarking — Ergon Energy submitted that our benchmarking approach appears to put to one side underlying revealed and recurrent costs of its business and that material problems remain with our benchmarking approach that are impacting on Ergon Energy.²¹

In arriving at this final decision we have considered all the material before us. This includes Ergon Energy's revised proposal and stakeholder submissions. We have also reviewed the analysis we made in reaching our preliminary decision in light of the new information we have since received. Further, we have conducted additional analysis where required. While we have accepted some of the arguments raised by Ergon Energy, including its revised base opex costs as the base for the forecast opex, we do not agree with all of their concerns. While we have departed from our preliminary decision in a few respects, our positions in this final decision are broadly in line with our preliminary decision.

2.3 Structure of the overview

This overview provides a summary of our final decision and its constituent components and is structured as follows:

- Section 3 provides a break-down of our revenue decision into its key components.
- Section 4 sets out our final decision on classification of services, control mechanisms and incentive schemes that will apply to Ergon Energy. These are decisions we make in addition to the building block revenue determination.
- Section 5 explains our views on the regulatory framework.
- Section 6 outlines Ergon Energy's process.

²⁰ Ergon Energy, *Revised regulatory proposal, Submission to the AER on its preliminary determination*, 3 July 2015, p. 12.

²¹ Ergon Energy, *Revised regulatory proposal, Submission to the AER on its preliminary determination*, 3 July 2015, p. 11.

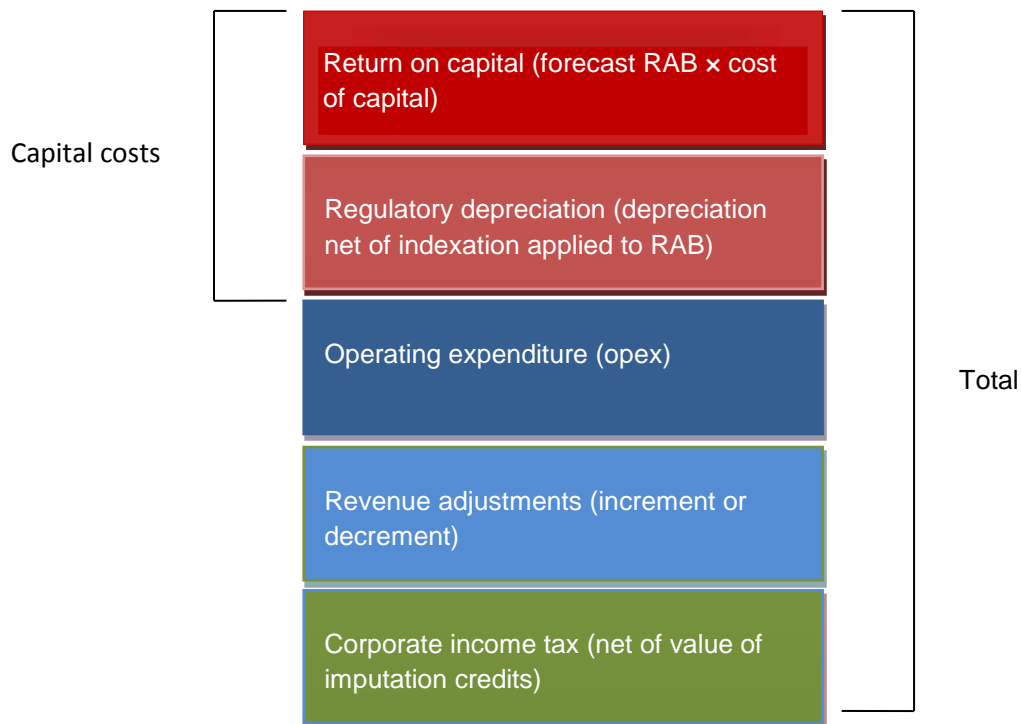
3 Key elements of the building blocks

We use the building block approach to determine Ergon Energy's annual revenue requirement. The building block costs, as illustrated in figure 5, include:²²

- a return on the regulatory asset base (RAB) (return on capital)
- depreciation of the RAB (return of capital)
- forecast opex
- revenue increments or decrements resulting from incentive schemes such as the efficiency benefit sharing scheme (EBSS)
- the estimated cost of corporate income tax.

Our assessment of capex directly affects the size of the RAB and therefore, the revenue generated from the return on capital and return of capital building blocks.

Figure 5 The building block approach for determining total revenue



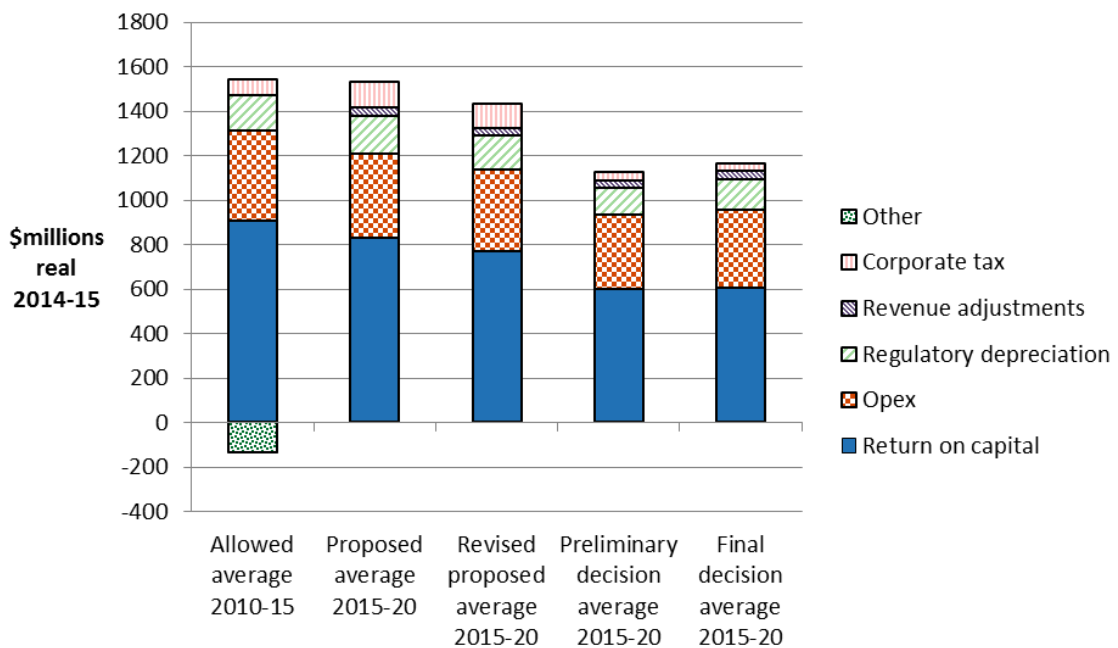
In setting the allowed revenue for Ergon Energy of \$6295.4 million (\$nominal) for the 2015–20 regulatory control period we:

²² Because Ergon Energy has a balance on its unders/overs account at the end of the 2010–15 regulatory control period, this will also be included as a building block. This is not shown in the illustration as typically a service provider should be aiming for a zero balance.

- apply relevant tests under the NER, the assessment methods and tools developed as part of our Better Regulation Guidelines.²³ We also consider information provided by Ergon Energy, the Consumer Challenge Panel (CCP), consultants and stakeholder submissions.
- consider our allowed revenue against section 16 of the NEL,²⁴ including the constituent components set out in the NER, how they interrelation with each other and how those interrelationships have been taken into account.

Figure 6 and table 2 show our final decision on Ergon Energy's revenue and the contribution of each building block.

Figure 6 AER's final decision on constituent components of total revenue (\$ million 2014–15)



Source: AER analysis.

Note: The 'Other' category in the 'Allowed average' for 2010–15 is a revenue adjustment related largely to customer contributions. Because customer contributions were included in the RAB during those years, an offsetting revenue adjustment was made to prevent Ergon Energy earning a return on these contributions. The 'Revenue adjustments' includes the closing balance of the DUoS unders/overs account as at 30 June 2015, the EBSS penalties/rewards related to the 2010–15 regulatory control period, the demand management innovation allowance and shared asset adjustments.

²³ www.aer.gov.au/Better-regulation.

²⁴ This specifies key policy considerations that we must apply when performing our economic regulatory functions.

Table 2 AER's final decision on Ergon Energy's revenues (\$ million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Return on capital	593.2	622.9	652.9	680.8	706.5	3256.4
Regulatory depreciation ^a	192.3	136.1	133.7	141.2	147.9	751.2
Operating expenditure	347.7	362.5	377.8	395.2	412.7	1896.0
Revenue adjustments ^b	90.5	46.3	66.8	–18.0	–2.9	182.8
Corporate tax allowance	43.7	30.6	29.0	36.2	40.0	179.6
Annual revenue requirement (unsmoothed)	1267.4	1198.4	1260.3	1235.5	1304.4	6266.0
Annual expected revenue (exc. additionals)	1137.7	1142.6	1335.1	1337.0	1343.0	6295.4
X factor ^c	n/a ^e	2.02%	–14.00%	2.30%	2.00%	n/a
Additional amounts in DUoS ^d	420.6	341.6	114.3	114.0	113.8	1104.3
Annual expected revenue (smoothed – inc. additionals)	1558.3	1484.2	1449.4	1451.0	1456.8	7399.7
Annual change in revenue (inc. additionals)	n/a	–4.8%	–2.3%	0.1%	0.4%	n/a

Source: AER analysis.

- (a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.
- (b) Revenue adjustments include efficiency benefit sharing scheme carry-overs, forecast DMIA, DUoS under-recoveries and shared asset adjustments.
- (c) The X factor from 2016–17 to 2019–20 will be revised to reflect the annual return on debt update.
- (d) Additional amounts in DUoS include Solar Bonus Scheme forecasts (jurisdictional scheme obligation for FiT) for 2015–20, estimated Solar Bonus Scheme pass throughs for 2015–16 and 2016–17 relating to under-recoveries in 2013–14 and 2014–15, estimated DUoS under-recovery for 2013–14, transitional capital contribution and shared assets under/over recovery from 2010–15, STPIS allowance from 2010–15 and DMIA over-recovery from 2010–15.
- (e) In our preliminary decision, we determined the expected revenue and associated X factor for 2015–16. In this final decision to update the 2015–16 revenue for our assessment of efficient costs, we maintained the preliminary decision expected revenue for 2015–16 and determined X factors for the final four years of the 2015–20 regulatory control period. This is to adjust Ergon Energy's total expected revenue requirement for the remaining four years in the 2015–20 regulatory control period for the difference between the preliminary decision revenue and our final decision on Ergon Energy's efficient costs for 2015–16.

3.1 Regulatory asset base

The RAB is the value of Ergon Energy's assets used to provide distribution network services. It is the value on which Ergon Energy earns a return on capital, and a

depreciation allowance (return of capital) on assets in its RAB. We assess Ergon Energy's proposed opening value for the RAB for each year of the 2015–20 regulatory control period.²⁵

Our final decision is to set Ergon Energy's opening RAB at \$9873.0 million (\$ nominal) as at 1 July 2015. We do not accept Ergon Energy's revised proposed opening RAB value of \$10 055.8 million (\$ nominal) as at 1 July 2015. This is because Ergon Energy's revised proposal repeated the error in its initial proposal of using incorrect remaining asset lives as at 1 July 2010. We also made adjustments to account for actual inflation for 2014–15, capitalised provisions and removal of other alternative control services (ACS) related assets besides meters.

For this final decision, we maintain our preliminary decision position on the use of forecast depreciation for establishing the RAB at the commencement of the regulatory control period from 1 July 2020. Ergon Energy's revised proposal noted our preliminary decision on this issue.²⁶

Tables 3 and 4 set out our final decision on the roll forward of Ergon Energy's RAB for the 2010–15 regulatory control period and the forecast RAB for Ergon Energy during the 2015–20 regulatory control period respectively.

Table 3 AER's final decision on Ergon Energy's RAB for the 2010–15 regulatory control period (\$ million, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15 ^a
Opening RAB	7148.9	7848.5	8370.7	9038.0	9641.3
Capital expenditure ^b	809.5	748.3	836.5	743.8	794.1
Inflation indexation on opening RAB	238.1	124.0	209.3	264.8	128.2
Less: straight-line depreciation	348.0	350.2	378.3	405.3	407.2
Closing RAB	7848.5	8370.7	9038.0	9641.3	10156.4
Difference between estimated and actual capex (1 July 2009 to 30 June 2010)					-132.8
Return on difference for 2009–10 capex					-76.4
Closing RAB as at 30 June 2015					9947.2
ACS (metering and other) assets removed					-74.2
Opening RAB as at 1 July 2015					9873.0

Source: AER analysis.

(a): Based on estimated capex. We will update the RAB roll forward in the substitute decision.

²⁵ NER, cl. 6.5.1 and S6.2.

²⁶ Ergon Energy, *Submission to the AER on its Preliminary Determination: SCS Building Blocks, Control Mechanism and Pricing*, 3 July 2015, p.13.

(b): Net of disposals and adjusted for CPI.

Table 4 AER's final decision on Ergon Energy's RAB for the 2015–20 regulatory control period (\$ million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20
Opening RAB	9873.0	10368.7	10867.7	11332.5	11760.3
Capital expenditure ^a	688.0	635.1	598.6	569.0	571.7
Inflation indexation on opening RAB	246.8	259.2	271.7	283.3	294.0
Less: straight-line depreciation	439.1	395.3	405.4	424.5	441.9
Closing RAB	10368.7	10867.7	11332.5	11760.3	12184.0

Source: AER analysis.

(a) Net of forecast disposals and capital contributions.

We determine a forecast closing RAB value at 30 June 2020 of \$12 184.0 million (\$ nominal). This is \$605.9 million (or 4.7 per cent) lower than the amount of \$12 789.9 million (\$ nominal) in Ergon Energy's revised proposal. Our final decision on the forecast closing RAB reflects our adjustments to Ergon Energy's opening RAB as at 1 July 2015, forecast capex (attachment 6), forecast regulatory depreciation (attachment 5), and the forecast inflation rate (attachment 3).

Details of our final decision on the value of the RAB are set out in attachment 2.

3.2 Rate of return (return on capital)

The return on capital provides a distributor with revenue to service the interest on its loans and to give a return on equity to shareholders. This building block is calculated as a product of the rate of return and the value of the RAB.²⁷

The NER sets out that the allowed rate of return must be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the distributor in respect of the provision of distribution services.²⁸ The NER refers to this requirement as the allowed rate of return objective.

We have determined an allowed rate of return of 6.01 per cent (nominal vanilla²⁹), subject to updating. We have not accepted Ergon Energy's proposed 7.41 per cent

²⁷ NER, cl. 6.5.2(a).

²⁸ NER, cl. 6.5.2(b).

²⁹ The nominal vanilla WACC combines a post-tax return on equity and a pre-tax return on debt, for consistency with other building blocks.

return.³⁰ In accordance with the Rate of Return Guideline, we will update the rate of return annually, consistent with Ergon Energy's revised proposal and our approach to return on debt.³¹ Table 5 sets out the parameters we have used to determine the rate of return.

Table 5 AER's final decision on Ergon Energy's rate of return (nominal)

	AER previous decision (2010–15)	Ergon Energy revised proposal (2015–16) ^(a)	AER final decision (2015–16)	Return over 2015–20 regulatory control period
Return on equity (nominal post-tax)	10.84%	10.00%	7.5%	Remains constant (7.5%)
Return on debt (nominal pre-tax)	8.98%	5.68%	5.01%	Updated annually
Gearing	60%	60%	60%	Remains constant (60%)
Nominal vanilla WACC	9.72%	7.41%	6.01%	Updated annually as return on debt is updated
Forecast inflation	2.52%	2.55%	2.50%	Remains constant (2.50%)

Source: AER analysis; Ergon Energy, *Revised regulatory proposal 2015-20*, July 2015; AER, *Final decision: Queensland distribution determination 2010–11 to 2014–15*, May 2010.

(a) Ergon Energy's revised proposal uses values derived from the placeholder averaging periods for risk free rate and rate on debt in its revised proposal.

Our approach

All NER requirements relating to the rate of return are subject to the overall rate of return achieving the allowed rate of return objective.³² The NER recognises that there may be several plausible answers that could achieve the allowed rate of return objective.³³ We agree with stakeholders that predictability in our approach to rate of

³⁰ Ergon Energy, *Revised regulatory proposal, Appendix C Rate of return*, 3 July 2015, p. 28.

³¹ NER, cl. 6.5.2(i)(2).

³² NER, cl. 6.5.2(b).

³³ AEMC, *Rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012: National gas amendment (Price and revenue regulation of gas services) Rule 2012*, 29 November 2012, p. 67 (AEMC, *Final rule change determination*, November 2012); AEMC, *Final rule change determination*, November 2012, p. iv, AEMC, *Final rule change determination*, November 2012, p. 38; The High Court of NZ stated: 'In determining WACC, precision is therefore an elusive and perhaps non-existent quality. Setting WACC is,

return issues, consistent with prevailing market conditions materially benefits the long term interests of consumers and benefits investors.³⁴

We developed our approach prior to the submission of Ergon Energy's initial regulatory proposal. As required by the rate of return framework, in December 2013, we published the Guideline³⁵ as contemplated by the NER.³⁶ The Guideline was developed through extensive consultation and involved effective and inclusive stakeholder participation.

Return on debt

Previously, we used an on-the-day approach to determine the return on debt.³⁷ This is the approach that many Australian regulators continue to use. We have determined a return on debt estimate that gradually transitions from an on-the-day approach to a trailing average approach.³⁸ This is consistent with the approach most stakeholders supported during the Guideline development process. In its initial regulatory proposal, Ergon Energy proposed a gradual transition to the trailing average approach. We accepted Ergon Energy's proposed approach on this issue in our preliminary decision.³⁹ However, in its revised regulatory proposal, Ergon Energy proposed a hybrid transition to the trailing average approach.⁴⁰

We have not accepted Ergon Energy's revised approach on this issue. We consider that Ergon Energy's proposed approach is backward looking and produces a biased estimate of the return on debt.

Return on equity

Ergon Energy did not adopt our approach to determining the return on equity.⁴¹ Our approach involves considering all the information before us, through a six step process as set out in the Guideline (foundation model approach). This includes detailed consideration of financial models for determining the return on equity.⁴² Considering all

we suggest, more of an art than a science. The use of WACC, in conjunction with RAB values, to set prices and revenue in price-quality regulation gives significance to WACC estimates that may not exist outside this context.¹ *Wellington International Airport Ltd & Others v Commerce Commission* [2013] NZHC 3289, para. 1189.

³⁴ ENA, *Response to the Draft Rate of Return Guideline of the AER*, 11 October 2013, p. 1; AER, *Better regulation: Explanatory statement rate of return Guideline, Appendices*, December 2013, Appendix I, Table I.4, pp.185–186.

³⁵ NER, cl. 6.5.2(m).

³⁶ NER, cl. 6.5.2(m).

³⁷ This involved determining the return on debt by reference to the return on BBB+ rated bonds over a 10-40 business day averaging period that occurred as close as practicable to the start of the 2015–20 regulatory control period.

³⁸ In broad terms, this means that over the longer term the return on debt for any year will represent the average return on debt over the previous ten years.

³⁹ AER, *Ergon Energy preliminary decision, Attachment 3: Rate of return*, April 2015, pp. 3-10 to 3-11.

⁴⁰ Ergon Energy, *Revised regulatory proposal, Appendix C Rate of return*, 3 July 2015, p. 143.

⁴¹ Ergon Energy, *Revised regulatory proposal, Appendix C Rate of return*, 3 July 2015, p. 131.

⁴² NER, cl. 6.5.2(e)(1).

of this material helps inform a return on equity estimate that contributes to the achievement of the allowed rate of return objective.

We consider that the Sharpe–Lintner capital asset pricing model (SLCAPM) is the superior financial model in terms of estimating expected equity returns. We have therefore adopted this model as our foundation model. We are persuaded by the expert evidence before us that indicates on balance that employing our foundation model approach and using the SLCAPM as the foundation model is expected to lead to a rate of return that achieves the allowed rate of return objective.⁴³

We also evaluated our point estimate from the SLCAPM against other information. The critical allowance for an equity investor in a benchmark efficient entity is the allowed equity risk premium (ERP) over and above the estimated risk free rate at any given time.⁴⁴ Our estimate of the ERP for the benchmark efficient entity is 4.55 per cent which is within range of other information available to inform the return on equity (see figure 7). Instead, Ergon Energy proposed that the return on equity be determined by applying all relevant models (the SL CAPM, Black CAPM, Dividend Discount Model and Fama-French model), as permitted under the NER.⁴⁵

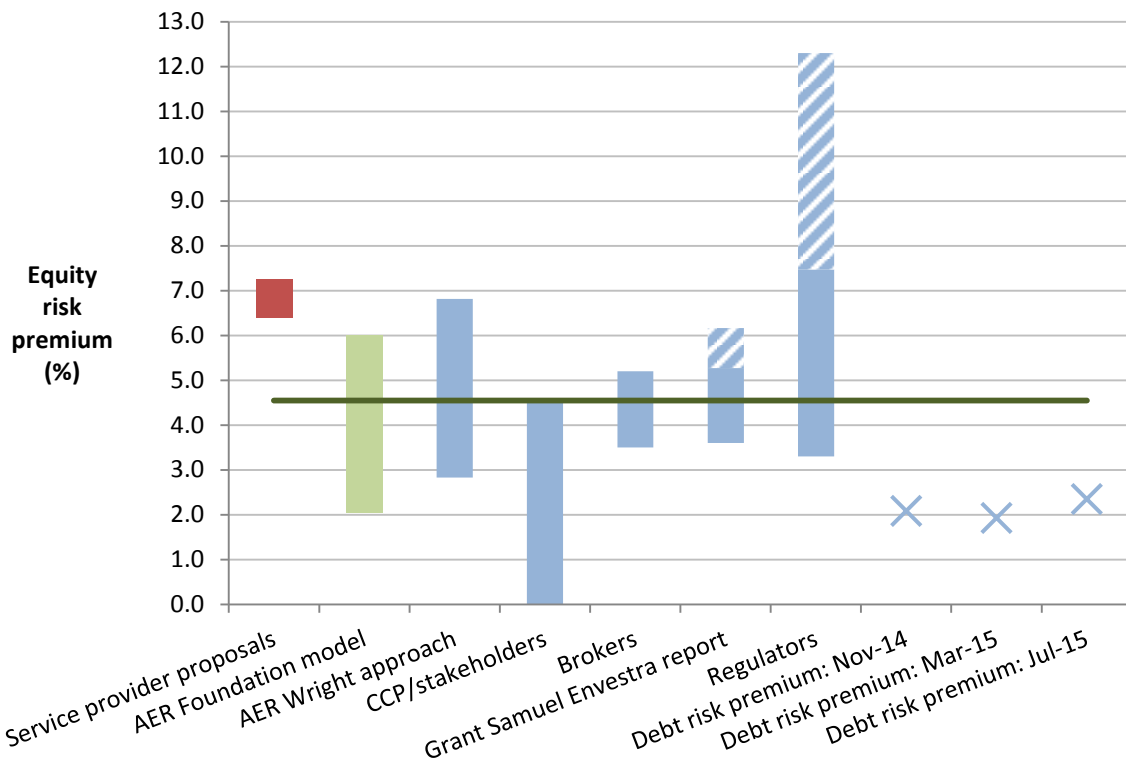
A detailed explanation of our findings on return on equity and this figure can be found in attachment 3: Rate of return.

⁴³ McKenzie & Partington, *Part A: Return on equity, Report to the AER*, October 2014, p. 13; John Handley, *Advice on return on equity, Report prepared for the AER*, October 2014, p. 3.

⁴⁴ Our task is to determine the efficient financing costs commensurate with the risk of providing regulated network service by an efficient benchmark entity (allowed rate of return objective). Risks in this context are those which are compensated via the return on equity (systematic risks).

⁴⁵ Ergon Energy, *Revised regulatory proposal, Appendix C Rate of return*, 3 July 2015, p. 142.

Figure 7 Other information comparisons with the AER allowed ERP



Source: AER analysis and various submissions and reports.

Notes: The AER foundation model equity risk premium (ERP) range uses the range and point estimate for MRP and equity beta as set out in step three. The calculation of the Wright approach, debt premium, brokers, and other regulators ranges is outlined in Appendices E.1, E.2, E.4, and E.5 respectively.

Grant Samuel's final WACC range included an uplift above an initial SLCAPM range. The lower bound of the Grant Samuel range shown above excludes the uplift while the upper bound includes the uplift and is on the basis that it is an uplift to return on equity. Grant Samuel made no explicit allowance for the impact of Australia's dividend imputation system. We are uncertain as to the extent of any dividend imputation adjustment that should be applied to estimates from other market practitioners. Accordingly, the upper bound of the range shown above includes an adjustment for dividend imputation, while the lower bound does not. The upper shaded portion of the range includes the entirety of the uplift on return on equity and a full dividend imputation adjustment.

The shaded portion of the other regulators range represents the impact of rail decisions on the range. We consider rail networks are unlikely to be comparable to the benchmark efficient entity.

The service provider proposals range is based on the proposals from businesses for which we are making final or preliminary decisions in October-December 2015. Equity risk premiums were calculated as the proposed return on equity less the risk free rate utilised in the service provider's proposed estimation approach.

The CCP/stakeholder range is based on submissions made (not including service providers) in relation to our final or preliminary decisions in October-December 2015. The lower bound is based on the Alliance of Electricity Consumers submission on Energex and Ergon Energy revised proposals. The upper bound is based on Origin Energy's submission on the preliminary decision for SA Power Networks.

3.3 Value of imputation credits (gamma)

Under the Australian imputation tax system, investors can receive an imputation credit for income tax paid at the company level.⁴⁶ These are received after company income tax is paid, but before personal income tax is paid. For eligible investors, this credit offsets their Australian income tax liabilities. If the amount of imputation credits received exceeds an investor's tax liability, that investor can receive a cash refund for the balance. Imputation credits are therefore a benefit to investors in addition to any cash dividend or capital gains they receive from owning shares.

In determining a service provider's revenue allowance, the NER requires that the estimated cost of corporate income tax be estimated in accordance with a formula that reduces the estimated cost by the 'value of imputation credits'.⁴⁷ That is, the revenue granted to a service provider to cover its expected tax liability must be reduced in a manner consistent with the value of imputation credits.

Our final decision is to adopt a value of imputation credits of 0.4. This differs from Ergon Energy's proposed value of imputation credits of 0.25.

Although we have broadly maintained the approach to determining the value of imputation credits set out in the Rate of Return Guideline, we have re-examined the relevant evidence and estimates since our preliminary decision. This re-examination, and new evidence and advice considered for the first time since the Guideline, led us to depart from the value of 0.5 in the Guideline. Most notably, our updated consideration of the relevant advice and evidence led us to generally lower estimates of the 'utilisation rate' from the 0.7 estimate in the Guideline.

Estimating the value of imputation credits is a complex and somewhat imprecise task. There is no consensus among experts on the appropriate value or estimation techniques to use.

Consistent with the relevant academic literature, we estimate the value of imputation credits as the product of the distribution rate and the utilisation rate. While there is a widely accepted approach to estimating the distribution rate, there is no single accepted approach to estimating the utilisation rate and there is a range of evidence relevant to the utilisation rate:

- the proportion of Australian equity held by domestic investors (the 'equity ownership approach').
- the reported value of credits utilised by investors in Australian Taxation Office (ATO) statistics ('tax statistics').

⁴⁶ *Income Tax Assessment Act 1997*, parts 3–6.

⁴⁷ NER, cl. 6.4.3(a)(4), 6.4.3(b)(4), 6.5.3.

- implied market value studies—there is no separate market in which imputation credits are traded, and therefore there is no observable market price for imputation credits.

In estimating the utilisation rate, we place:

- significant reliance upon the equity ownership approach
- some reliance upon tax statistics
- less reliance upon implied market value studies.

Overall, the evidence on the distribution rate and the utilisation rate suggests that a reasonable estimate of the value of imputation credits is within the range of 0.3 to 0.5. From within this range, we choose a value of 0.4. This is because:

- the equity ownership approach, on which we have placed the most reliance, suggests a value between 0.40 and 0.47 when applied to all equity and between 0.29 and 0.42 when applied to only listed equity. Therefore, the overlap of the evidence from the equity ownership approach suggests a value between 0.40 and 0.42.
- the evidence from tax statistics suggests the value could be lower than 0.4. Therefore, with regard to this evidence and the less reliance we place on it, we choose a value at the lower end of the range suggested by the overlap of evidence from the equity ownership approach (that is, 0.4).
- an estimate of 0.4 is reasonable in light of both higher and lower estimates from implied market value studies and the lesser degree of reliance we place on these studies. The service providers submitted evidence to support placing more reliance on SFG's dividend drop off study relative to other implied market value studies. However, we consider that neither the difference from 0.4 of the estimate from this study (0.31) nor any increased reliance we might place on it relative to other implied market value studies are sufficient to warrant an estimate lower than 0.4.

3.4 Regulatory depreciation (return of capital)

Depreciation is the allowance provided so that capital investors recover their investment over the economic life of the asset (return of capital). We are required to decide on whether to approve the depreciation schedules submitted by Ergon Energy.⁴⁸ In doing so, we make determinations on the indexation of the RAB and depreciation building blocks for Ergon Energy's 2015–20 regulatory control period. The regulatory depreciation allowance is the net total of straight-line depreciation less the indexation of the RAB.

Our final decision is to determine a regulatory depreciation allowance of \$751.2 million (\$ nominal) for Ergon Energy. This amount represents a decrease of \$77.9 million (\$

⁴⁸ NER, cl. 6.12.1(8).

nominal) (or 9.4 per cent) of the \$829.1 million (\$ nominal) Ergon Energy proposed for the 2015–20 regulatory control period.⁴⁹

Table 6 sets out our final decision on Ergon Energy's depreciation allowance for the 2015–20 regulatory control period.

Table 6 AER's final decision on Ergon Energy's depreciation allowance for the 2015–20 regulatory control period (\$ million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Straight-line depreciation	439.1	395.3	405.4	424.5	441.9	2106.3
Less: inflation indexation on opening RAB	246.8	259.2	271.7	283.3	294.0	1355.1
Regulatory depreciation	192.3	136.1	133.7	141.2	147.9	751.2

Source: AER analysis.

In determining this allowance we accept Ergon Energy's proposed asset classes, straight-line depreciation method and standard asset lives. However, our reduction to Ergon Energy's proposed regulatory depreciation reflects our decision:

- to make some changes to the implementation of the revised approach by Ergon Energy to determine remaining asset lives and depreciation associated with existing assets. This corrects errors in Ergon Energy's revised proposal.
- on other components of Ergon Energy's revised proposal which affect the forecast regulatory depreciation allowance—for example, the opening RAB at 1 July 2015 (attachment 2), forecast inflation rate (attachment 3) and forecast capex (attachment 6).⁵⁰

Details of our final decision on the regulatory depreciation allowance are set out in attachment 5.

3.5 Capital expenditure

Capex refers to the capital expenses incurred in the provision of network services. The return on and return of forecast capex for standard control services are two of the building blocks we use to determine a service provider's total revenue requirement.

We estimate total forecast capex of \$2858.1 million (\$2014–15) for Ergon Energy's 2015–20 regulatory control period. This is down from \$3282.4 million (\$2014–15) or 12.9 per cent on Ergon Energy's proposed capex.

Table 7 shows our final decision compared to Ergon Energy's revised proposal.

⁴⁹ Ergon Energy, *Revised regulatory proposal*, July 2015, p. 29.

⁵⁰ NER, cl. 6.5.5(a)(1).

Table 7 AER final decision on total net capex (\$million 2014–15)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Ergon Energy's revised proposal	749.4	685.6	634.3	610.6	602.6	3,282.4
AER final decision	667.0	601.4	553.6	522.6	513.5	2858.1
Difference	82.4	84.2	80.7	88.0	89.1	424.3
Percentage difference (%)	–11.0	–12.3	–12.7	–14.4	–14.8	–12.9

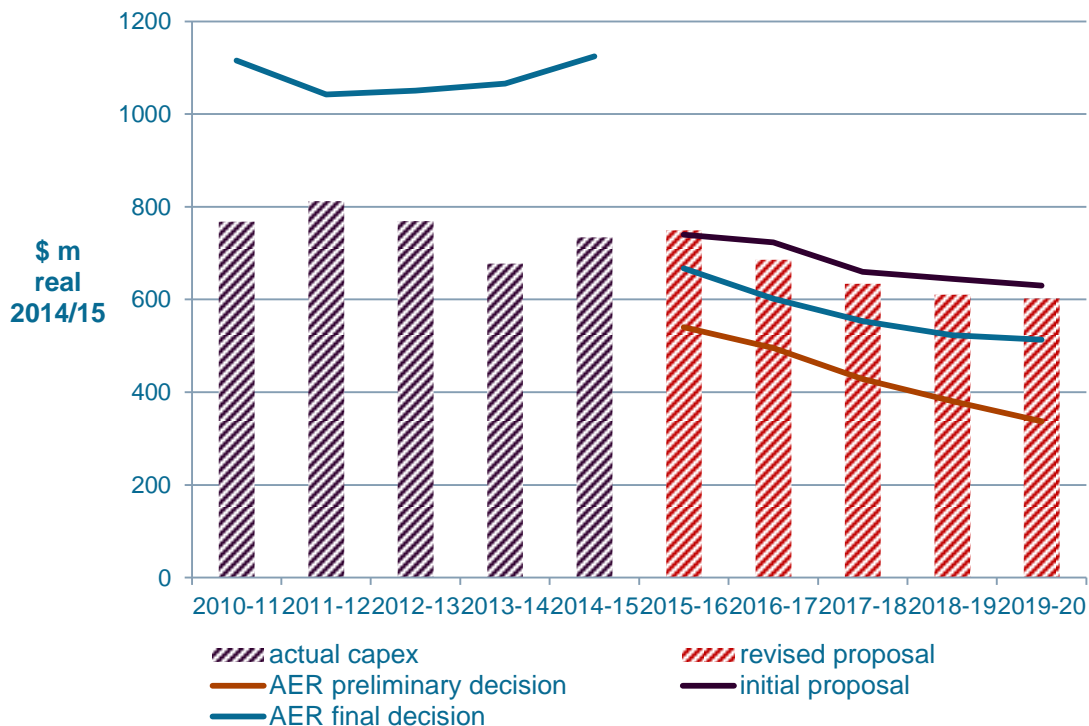
Source: Ergon Energy, *Revised regulatory Proposal*; AER analysis.

Note: Numbers may not add up due to rounding.

Note: Net capex excludes capital contributions.

Figure 8 shows Ergon Energy's initial proposal, its revised proposal and our preliminary and final decisions for capex for the 2015–20 regulatory control period. It also shows the actual capex that Ergon Energy spent during the 2010–15 regulatory control period.

Figure 8 AER's preliminary and final decisions compared to Ergon Energy's past and proposed capex (\$million 2014–15)



Source: AER analysis.

We examined Ergon Energy's forecasting methodology, key assumptions and past capex performance. Attachment 6 sets out our detailed reasons for our final decision on Ergon Energy's total forecast capex.

The key points of our capex estimate for Ergon Energy are:⁵¹

- Our substitute estimate of total capex includes \$543.7 million (\$2014–15) for augmentation expenditure (augex).⁵² This is 11 per cent lower than Ergon Energy's revised augex proposal of \$608 million. We accept the majority of Ergon Energy's revised augex forecast reasonably reflects the capex criteria, including to meet some areas of modest growth in forecast maximum demand. However, our augex estimate is lower because we consider Ergon Energy's forecast cost to address voltage problems on its network and its system-enabling capex projects are overstated.
- We estimate \$786.6 million (\$2014–15) for Ergon Energy's replacement expenditure (repex). This is 16 per cent lower than Ergon Energy's revised repex forecast of \$941 million. As part of our estimate, we accept Ergon Energy's revised forecasts for SCADA, "other" capex and remediation of low lines. Our repex estimate is lower than Ergon Energy's forecast because our business-as-usual repex estimate is lower than Ergon Energy's forecast. Also, our repex estimate is lower because we used Ergon Energy's current allowance for pole top structure repex rather than its higher forecast.
- Our preliminary decision accepted Ergon Energy's forecast for connections capex of \$419.8 million (\$2014–15). This includes Ergon Energy's forecast for customer contributions of \$158.8 million (\$2014–15). We accepted the forecasts after considering long term trends. Also, we consider the forecasts are consistent with expected construction activity in Queensland.
- We accept Ergon Energy's revised forecast for non-network capex of \$406.6 million (\$2014–15). This is a reduction of \$23.3 million (\$2014–15) from Ergon Energy's initial proposal. This reflects a reduction in Ergon Energy's forecast for vehicle fleet capex, driven by changes to its fleet management and forecasting approaches.
- We do not accept Ergon Energy's proposed capitalised overheads of \$1051.4 million (\$2014–15). We have instead included in our substitute estimate of overall total capex an amount of \$1035.3 million (\$2014–15) for capitalised overheads. This reduction in forecast overheads reflects our direct capex forecast that is expected to attract overhead expenditure.

⁵¹ We obtained Ergon Energy's proposed capex numbers from its RIN. Our assessment used information subsequently provided by Ergon Energy.

⁵² Excluding overheads.

3.6 Operating expenditure

Opex is non-capital expenditure incurred in the provision of distribution network services. It includes labour and other non-capital costs that Ergon Energy is likely to require to operate and maintain its network during the 2015–20 regulatory control period.

Ergon Energy forecast total opex of \$1841.8 million (\$2014–15) over the 2015–20 regulatory control period. Our final decision is we are not satisfied Ergon Energy’s forecast opex reasonably reflects the opex criteria. Where we find that a service provider’s forecast does not reasonably reflect the opex criteria, the NER instructs us to not accept it and replace it with a forecast that we are satisfied reasonably reflects the opex criteria.

Attachment 7 sets out our detailed reasons for our final decision on Ergon Energy’s total forecast opex. We compare our estimate with Ergon Energy’s revised proposal in table 8.

Table 8 AER final decision on total opex (\$ million, 2014–15)

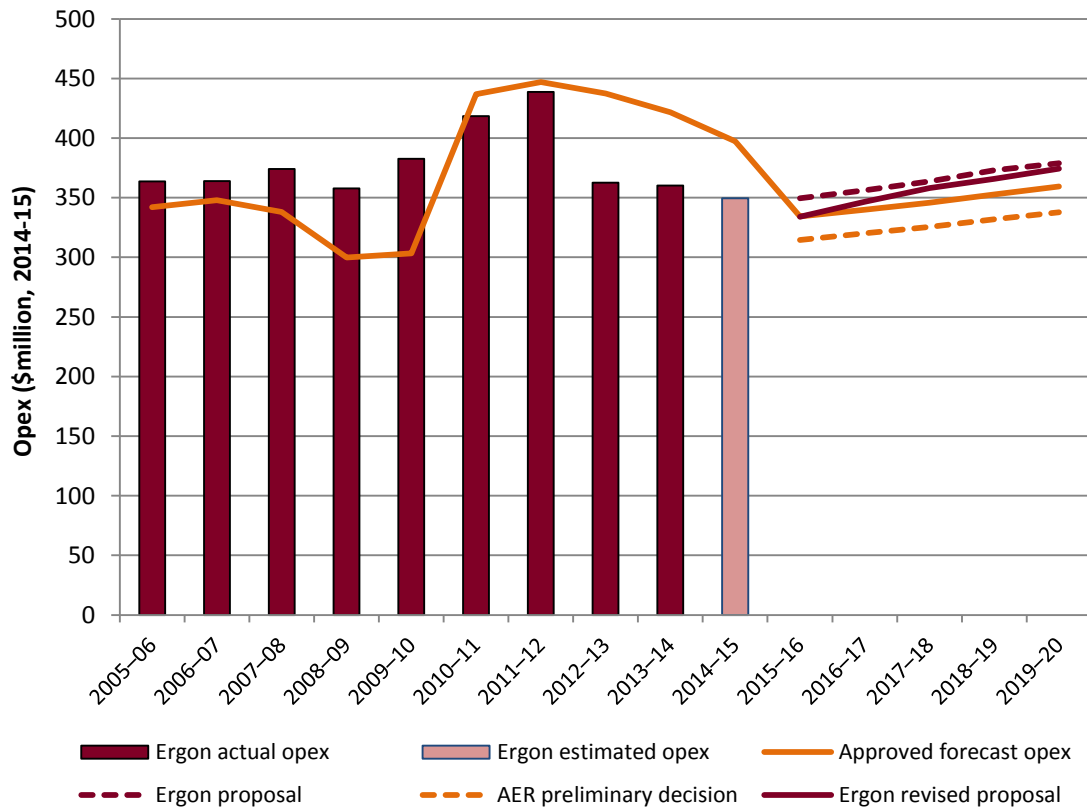
Year ending 30 June	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Ergon Energy’s revised proposal	345.9	358.9	370.8	378.8	387.4	1841.8
AER final decision	339.2	345.1	350.8	358.1	364.8	1757.9
Difference	–6.7	–13.8	–20.0	–20.7	–22.6	–83.9

Source: AER analysis.

Note: Includes debt raising costs.

Figure 9 shows our final decision compared to Ergon Energy’s revised opex proposal, its past allowances and past actual expenditure.

Figure 9 AER final decision compared to Ergon Energy's past and proposed opex (\$million, 2014–15)



Note: The opex for the period 2005–06 to 2014–15 include some services that have been reclassified as ancillary reference services; the forecast opex for period 2015–16 to 2019–20 does not. The opex for the period 2005–06 to 2009–10 also includes debt raising costs; the opex and forecast opex for the period 2010–11 to 2019–20 do not.

Source: Ergon Energy, Regulatory accounts 2005–06 to 2009–10; Ergon Energy 2010–11 to 2014–15 PTRM, Annual Reporting RIN 2010–11 to 2013–14, *Regulatory proposal*, *Revised regulatory proposal*; AER analysis.

Unlike in our preliminary decision, for the final decision we are using Ergon Energy's reported opex for 2013–14 as the basis for forecasting total opex. The difference between our forecast opex and Ergon Energy's revised proposal reflects our views on step changes. However, much of the difference is offset by efficiency improvements proposed by Ergon Energy in the forecast period and our change in approach for base opex. There is, therefore, only a moderate difference between Ergon Energy's revised proposal and our final decision.

3.6.1 Step changes

We have included one step change in our opex forecast. We are satisfied that additional opex associated with Ergon Energy's market transaction centre arises due to a changed regulatory obligation.

We are not satisfied there are reasons to change our opex forecast for any other step changes. In particular, we have not included a step change of \$66 million for a new insurance policy relating to cyclones and storms. We consider Ergon Energy has not sufficiently demonstrated it would be more efficient to purchase the new policy rather than to retain the risk itself.

3.6.2 Base opex

One of the key drivers of the difference between Ergon Energy's initial opex proposal and our preliminary decision was base opex. In the preliminary decision we did not use Ergon Energy's revealed expenditure as the basis for determining our estimate of total forecast opex because we found it to be materially inefficient. While we did not depart from most of the positions concerning base year opex in our preliminary decision, we no longer consider Ergon Energy's revealed expenditure is materially inefficient. There are two main reasons for this.

First, we have adjusted the efficiency score that we have assessed Ergon Energy's proposed base year opex against by:

- removing metering opex that was incorrectly included by Ergon Energy in its network services opex
- using non-coincident maximum demand data consistently for Australia, New Zealand and Ontario in our econometric benchmarking models
- increasing the operating environment factor (OEF) adjustments that we have applied for cyclones and OH&S obligations by 1.8 per cent, increasing the total OEF adjustment from 24.4 to 26.2 per cent.

Second, the fact that there is only a 1.4 per cent difference between our estimate and Ergon Energy's revealed expenditure is consistent with Ergon Energy having reduced the amount of actual opex that it has incurred over the past two years. This points to an improvement in Ergon Energy's efficiency relative to other service providers in the NEM.

3.7 Corporate income tax

The NER requires us to make a decision on the estimated cost of corporate income tax for Ergon Energy's 2015–20 regulatory control period.⁵³ The estimated cost of corporate income tax contributes to our determination of the total revenue requirements for Ergon Energy over the 2015–20 regulatory control period. It enables Ergon Energy to recover the costs associated with the estimated corporate income tax payable during that period.

Our final decision is to determine the estimated cost of corporate income tax of \$179.6 million (\$ nominal) for Ergon Energy over the 2015–20 regulatory control

⁵³ NER, cl. 6.4.3(a)(4).

period as shown in table 9. We do not accept Ergon Energy's revised proposal cost of corporate income tax allowance of \$601.3 million (\$ nominal). This represents a reduction of \$421.7 million (or 70.1 per cent) from Ergon Energy's revised proposal.

Table 9 AER's final decision on Ergon Energy's cost of corporate income tax allowance for the 2015–20 regulatory control period (\$ million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Tax payable	72.9	51.0	48.3	60.3	66.7	299.3
Less: value of imputation credits	29.2	20.4	19.3	24.1	26.7	119.7
Net corporate income tax allowance	43.7	30.6	29.0	36.2	40.0	179.6

Source: AER analysis.

Our final decision reflects our amendments to some of Ergon Energy's proposed inputs for forecasting the cost of corporate income tax such as the opening tax asset base and the remaining tax asset lives. It also reflects our final decision on the value of imputation credits (gamma) discussed in attachment 4. Changes to the building block costs also affect revenue, which in turn impacts the tax calculation. The changes affecting revenue are discussed in attachment 1.

Details of our final decision on the corporate income tax allowance are set out in attachment 8.

4 Classification of services, control mechanisms and schemes

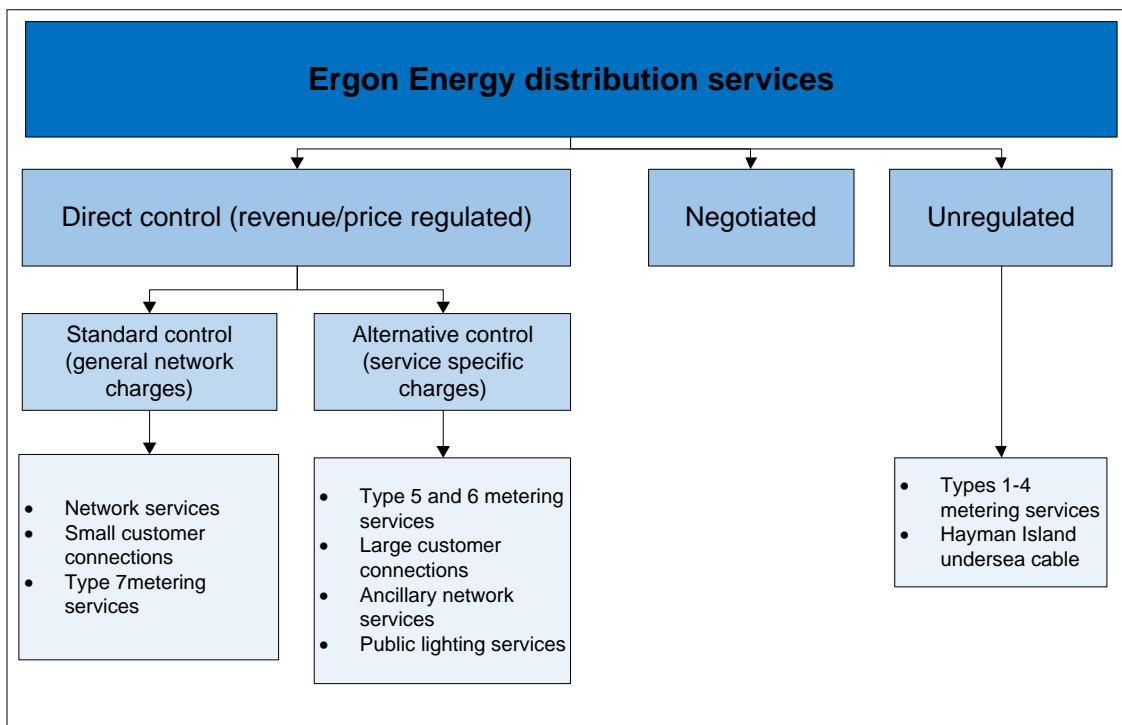
A range of factors, in addition to the building blocks, affect Ergon Energy's revenue. These include service classification, control mechanism, our approach to services charged to individual consumers and incentive schemes to promote efficiency. This section sets out our final decisions these issues.

4.1 Classification of services and control mechanisms

Service classification determines the nature of economic regulation, if any, applicable to specific distribution services. Classification is important to customers as it determines which network services are included in basic electricity charges, the basis on which additional services are sold, and those services we will not regulate. Our final decision reflects our assessment of a number of factors, including existing and potential competition to supply these services.

Our final decision is to retain the classification structure as set out in our preliminary decision. Figure 10 summarises our final decision on service classifications for the 2015–20 regulatory control period.

Figure 10 AER's final decision on 2015–20 service classifications for Ergon Energy



Source: AER.

Consistent with our preliminary decision, Ergon Energy will be subject to a 'revenue cap' form of control for standard control services over the 2015–20 regulator control period. The control mechanism (which describes how revenue will vary from year to year) is discussed in attachments 14 and 16. The control mechanism for standard control services is described in mathematical terms and reflects all possible adjustments that might be made to the revenue cap.

4.2 Alternative control services

Alternative control services do not form part of Ergon Energy's revenue cap. Rather, the prices of these services are set individually. Our final decision is to maintain the approach adopted in our preliminary decision, that the form of control mechanism to apply to Ergon Energy's alternative control services will be price caps. Ergon Energy must demonstrate compliance with the control mechanism through an annual pricing proposal.

Our final decision approves a structure of metering charges which has a capital and non-capital component. This “two-part tariff” gives effect to a regulatory regime that is robust enough to transition to competition. In accordance with an AEMC draft determination and draft rule, competition in metering and related services is scheduled to occur on 1 July 2017.⁵⁴

The approved two part tariff structure is largely unchanged from our preliminary decision. This is with the exception of a reallocation of Ergon Energy's recovery of its tax liability costs, from the non-capital to the capital component. For more information about the approved structure of metering charges refer to attachment 16 (appendix B).

4.3 Incentive schemes

Incentive schemes are a component of incentive-based regulation and complement our approach to assessing efficient costs. The incentive schemes that will apply to Ergon Energy are the:

- efficiency benefit sharing scheme (EBSS)
- capital expenditure sharing scheme (CESS)
- service target performance incentive scheme (STPIS)
- demand management incentive scheme (DMIS).

Our incentive schemes encourage network businesses to make efficient decisions. They give network businesses an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers. Incentives for opex and capex are balanced (approximately 30 per cent) and constant. They are also balanced with the incentives under our service target performance incentive scheme. This encourages

⁵⁴ AEMC, *Draft Rule Determination, National Electricity Amendment (Expanding competition in metering related services) Rule 2015*, 26 March 2015.

businesses to make efficient decisions on when and what type of expenditure to incur, in order to meet or exceed service reliability targets.

4.3.1 Efficiency benefit sharing scheme

The EBSS provides an additional incentive for service providers to pursue efficiency improvements in its opex.

As opex is largely recurrent and predictable, opex in one period is often a good indicator of opex in the next period (step changes provide for increases where this is not the case). Where a service provider is relatively efficient, we use the actual opex it incurred in a chosen base year of the regulatory control period to forecast opex for the next regulatory control period. We call this the 'revealed cost approach'.

To encourage a distributor to become more efficient during the regulatory control period it is allowed to keep any difference between its approved forecast and its actual opex during a regulatory control period. This is supplemented by the EBSS which allows the distributor to retain efficiency savings and efficiency losses for a longer period of time.⁵⁵ In total these rewards and penalties work together to provide a continuous incentive for a service provider to pursue efficiency gains over the regulatory control period. The combined effect of our revealed cost forecasting approach and the EBSS is that opex efficiency savings or losses are shared approximately 30:70 between the network businesses and consumers. For example, for a one dollar saving in opex the network business gets 30 cents of the benefit while consumers get 70 cents of the benefit.

The EBSS also discourages a distributor from incurring opex in the expected base year in order to receive a higher opex allowance in the following regulatory control period.⁵⁶

Our final decision for the EBSS carryover amounts from the 2010–15 regulatory control period is outlined in table 10. The difference between Ergon Energy's revised proposal and our final decision mostly reflects an adjustment we have made for Regulatory Information Notice reporting costs.

Table 10 AER's final decision on Ergon Energy's EBSS carryover amounts (\$ million, 2014–15)

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Ergon Energy's revised proposal	33.8	47.9	63.8	-18.3	0.0	127.2
AER's final decision	33.8	46.6	64.6	-13.8	0.0	131.2

Source: AER analysis; Ergon Energy, PTRM in revised proposal for the 2015–20 regulatory control period.

⁵⁵ Without this, the incentive would be greatest to make savings in the first year of the regulatory control period.

⁵⁶ These concepts are explained more fully in the explanatory statement to the EBSS, AER, *Efficiency benefit sharing scheme for electricity network service providers - explanatory statement*, November 2013.

We have determined that version two of the EBSS will apply to Ergon Energy during the 2015–20 regulatory control period.⁵⁷ This is a change in position from our preliminary decision which was not to apply the EBSS. We have changed our position on applying the EBSS because we have changed our position on using Ergon Energy's revealed costs to forecast its opex. In our preliminary decision, we based our opex forecast on a benchmark. We do not consider the EBSS should apply when using a benchmarking approach to forecast opex. However in our final decision we have used Ergon Energy's revealed costs to forecast its opex. Where we use this approach, we consider an EBSS is needed to incentivise efficient opex.

Our final decision on the EBSS for Ergon Energy is discussed in attachment 9.

4.3.2 Capital expenditure sharing scheme

The CESS provides a network service provider with the same reward for an efficiency saving and same penalty for an efficiency loss regardless of which year they make the saving or loss. Consumers benefit from improved efficiency through lower regulated prices.

Under the CESS a service provider retains 30 per cent of the benefit or cost of an underspend or overspend, while consumers retain 70 per cent of the benefit or cost of an underspend or overspend. This means that for a one dollar saving in capex the service provider keeps 30 cents of the benefit while consumers keep 70 cents of the benefit. Conversely, in the case of an overspend, the service provider pays for 30 cents of the cost while consumers bear 70 cents of the cost.

For capex, the sharing of underspends and overspends happens at the end of each regulatory control period when we update a network service provider's RAB to include new capex. If a network service provider spends less than its approved forecast during a period, it will benefit within that period. Consumers benefit at the end of that period when the RAB is updated to include less capex compared to if the service provider had spent the full amount of the capex forecast.

Our final decision, consistent with our preliminary decision, is to apply version 1 of the CESS, as set out the Capital Expenditure Incentives Guideline, to Ergon Energy in the 2015–20 regulatory control period as Ergon Energy initially proposed.⁵⁸ Ergon Energy accepted our preliminary decision on this issue (provided the EBSS was also applied, which we have decided to do).⁵⁹ Attachment 10 sets out our reasons for our final decision on CESS.

⁵⁷ AER *Efficiency benefit sharing scheme for electricity network service providers*, November 2013.

⁵⁸ Ergon Energy, *Regulatory Proposal*, October 2014, p. 29.

⁵⁹ Ergon Energy, *Revised regulatory proposal, Submission on incentive schemes*, 3 July 2015, p. 12.

4.3.3 Service target performance incentive scheme (STPIS)

Consistent with our preliminary decision, our final decision is to apply the service standards component (the s-factor) of our national STPIS to Ergon Energy for the 2015–20 regulatory control period. We will not apply the guaranteed service level (GSL) component to Ergon Energy as the existing Queensland arrangements will continue to apply. We have accepted Ergon Energy's proposal to cap revenue at risk under the scheme at ± 2.0 per cent.

The national STPIS is intended to balance the incentives to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing appropriate financial incentives to distributors to maintain and improve service performance (at the level where customers are willing to pay for these improvements).⁶⁰ Hence, the STPIS also provides an incentive for distributors to invest in further reliability improvements (via additional capex or opex) where customers are willing to pay for it. Conversely, the STPIS penalises distributors where they let reliability deteriorate beyond the acceptable level valued by customers. Importantly, the distributor will only receive a financial reward after actual improvements are delivered to the customers.

Distributors can only retain their rewards for sustained and continuous improvements to the reliability of supply to customer. Once improvements are made, the benchmark performance targets will be tightened in future years.

In conjunction with the EBSS and CESS, the STPIS will ensure that:

- any additional investments to improve reliability are based on prudent economic decisions
- reductions in capex are achieved efficiently, rather than at the expense of service levels to customers.

In setting the STPIS performance targets, we have considered both completed and planned reliability improvements expected to materially affect network reliability performance. By setting the performance targets in such a way, any incentive a distributor may have to reduce the capex at the expense of target service levels should be curtailed by the STPIS financial penalties.

Attachment 11 sets out our final decision on Ergon Energy's service component parameter values.

⁶⁰ AER, *Electricity distribution network service providers—service target performance incentive scheme*, 1 November 2009.

4.3.4 Demand management incentive scheme

The DMIS includes a demand management innovation allowance (DMIA). The DMIA is a capped allowance for distributors to investigate and conduct broad based and/or peak demand management projects.

We have determined to continue Part A of the DMIS for Ergon Energy in the 2015–20 regulatory control period (that is, the DMIA component). This is consistent with our preliminary decision.⁶¹ Ergon Energy accepted our preliminary decision on this issue.⁶²

The current innovation allowance amount of \$1 million (\$2014–15) per annum will continue in the 2015–20 regulatory control period.

Attachment 12 sets out our final decision on Ergon Energy's DMIS.

⁶¹ AER, *Preliminary decision Ergon Energy distribution determination 2015-16 to 2019-20, Attachment 12 – Demand management incentive scheme*, April 2015, p. 7.

⁶² Ergon Energy, *Revised regulatory proposal, Submission on incentive schemes*, 3 July 2015, p. 18.

5 Understanding the NEO

The NEO is the central feature of the regulatory framework. The NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—

price, quality, safety, reliability and security of supply of electricity; and
the reliability, safety and security of the national electricity system.⁶³

Energy Ministers have provided us with a substantial body of explanatory material that guides our understanding of the NEO.⁶⁴ The long term interests of consumers are not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.⁶⁵

In general, we consider that we will achieve this balance and, therefore, contribute to the achievement of the NEO, where consumers are provided a reasonable level of safe and reliable service that they value at least cost in the long run.⁶⁶ We have also considered the quality and reliability of services provided to consumers. For example, opex allowances have been set so Ergon Energy may meet existing and new regulatory requirements. Repex allowances take into account the age and condition of assets. We have allowed sufficient augex and connections capex to cater for expected areas of growth. Our capex allowance is based on a contemporary estimate of the value of customer reliability. And the STPIS encourages maintenance, and indeed improvement of, service quality.

The nature of decisions under the NER is such that there may be a range of economically efficient decisions, with different implications for the long term interests of consumers.⁶⁷ At the same time, however, there are a range of outcomes that are unlikely to advance the NEO, or advance the NEO to the degree that others would.

For example, we do not consider that the NEO would be advanced if the allowed revenue encourage overinvestment and result in prices so high that consumers are unwilling or unable to efficiently use the network.⁶⁸ This could have significant longer term pricing implications for those consumers who continue to use network services.

⁶³ NEL, s. 7.

⁶⁴ Hansard, SA House of Assembly, 9 February 2005, pp. 1451–1460.
Hansard, SA House of Assembly, 27 September 2007, pp. 963–972.
Hansard, SA House of Assembly, 26 September 2013, pp. 7171–7176.

⁶⁵ Hansard, SA House of Assembly, 26 September 2013, p. 7173.

⁶⁶ Hansard, SA House of Assembly, 9 February 2005, p. 1452.

⁶⁷ *Re Michael: Ex parte Epic Energy* [2002] WASCA 231 at [143].

Energy Ministers also accept this view – see Hansard, SA House of Assembly, 26 September 2013 p. 7172.

AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, p. 50.

⁶⁸ NEL, s. 7A(7).

Equally, we do not consider the NEO would be advanced if the allowed revenue result in prices so low that investors are unwilling to invest as required to adequately maintain the appropriate quality and level of service, and where customers are making more use of the network than is sustainable. This could create longer term problems in the network⁶⁹ and could have adverse consequences for safety, security and reliability of the network.

The NEL also includes the revenue and pricing principles (RPP), which support the NEO.⁷⁰ As the NEL requires,⁷¹ we have taken the RPPs into account throughout our analysis. The RPPs are:

A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—

- providing direct control network services; and
- complying with a regulatory obligation or requirement or making a regulatory payment.

A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—

- efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
- the efficient provision of electricity network services; and
- the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted—

- in any previous—
- as the case requires, distribution determination or transmission determination; or
- determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or
- in the Rules.

A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks

⁶⁹ NEL, s. 7A(6).

⁷⁰ NEL, s. 7A.

⁷¹ NEL, s. 16(2).

involved in providing the direct control network service to which that price or charge relates.

Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

Consistent with Energy Ministers' views, we set revenue allowances to balance all elements of the NEO and consider each of the RPPs.⁷² For example:

- In determining forecast opex and capex that reasonably reflects the opex and capex criteria, we take into account the revenue and pricing principle that we should provide Ergon Energy with a reasonable opportunity to recover at least efficient costs. (Refer to capex attachment 6 and opex attachment 7).
- We take into account the economic costs and risks of the potential for under and over investment by a network service provider in our assessment of Ergon Energy's forecast capex and opex proposals. (Refer to capex attachment 6 and opex attachment 7).
- We consider the economic costs and risks of the potential for under and over utilisation of Ergon Energy's distribution system in our demand forecasting and augmentation determinations (Refer to capex attachment 6).
- Our application of the EBSS, CESS, STPIS and DMIS in this determination provides Ergon Energy with effective incentives which we consider will promote economic efficiency with respect to the direct control services that Ergon Energy provides throughout the regulatory control period. (Refer to attachments 9, 10, 11 and 12).
- We have determined Ergon Energy's opening RAB taking into account the RAB adopted in the previous distribution determination. (Refer to attachment 2, regulatory asset base).
- The allowed rate of return objective reflects the revenue and pricing principle in s.7A(5). We have determined a rate of return that we consider will provide Ergon Energy with a return commensurate with the regulatory and commercial risks involved in providing direct control services. (Refer to attachment 3, rate of return).
- Our financing determinations provide the distributor with a reasonable opportunity to recover at least the efficient costs of accessing debt and capital. (Refer to attachment 3, rate of return).

⁷² Hansard, *SA House of Assembly*, 27 September 2007, p. 965; Hansard, *SA House of Assembly*, 26 September 2013, p. 7173.

In some cases, our approach to a particular component (or part thereof) results in an outcome towards the end of the range of options that may be favourable to the businesses, for example, our choice of equity beta. While it can be difficult to quantify the exact revenue impact of these individual decisions, we have identified where we have done so in our attachments. Some of these decisions include:

- selecting at the top of the range for the equity beta
- setting the return on debt by reference to data for a BBB broad band credit rating, when the benchmark is BBB+
- the cash flow timing assumptions in the post-tax revenue model.

We take into account the RPPs when exercising discretion about an appropriate estimate. This requires a recognition that for the long term interests of consumers, the risk of under compensation for, or underinvestment by, a service provider may be less desirable than the risk of overcompensation or overinvestment. However, we are also conscious of the risk of introducing an inherent bias towards higher amounts where estimates throughout the different components of the determination are each set too conservatively.⁷³ The legislative framework recognises the complexity of this task by providing us with significant discretion in many aspects of the decision-making process to make judgements on these matters.

Chapter 6 of the NER provides specifically for the economic regulation of distributors. It includes rules about the constituent components of our decisions. These are intended to contribute to the achievement of the NEO.⁷⁴

5.1 Achieving the NEO to the greatest degree

A distribution determination is a complex decision and must be considered as such. In most instances, the provisions of the NER do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgement. For example, chapter 6 of the NER requires us to prepare forecasts, which are predictions about unknown future circumstances. As a result, there will likely always be more than one plausible forecast. There is substantial debate amongst stakeholders about the costs we must forecast, with both sides often supported by expert opinion. As a result, for certain components of our decision there may be several plausible answers or several point estimates within a range.

When the constituent components of our decision are considered together, this means there will almost always be several potential, overall decisions. More than one of these

⁷³ AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, 16 November 2016, p. 52.

⁷⁴ NEL, s. 88.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, p. 8.

may contribute to the achievement of the NEO. Where this is the case, our role is to make an overall decision that we are satisfied contributes to the achievement of the NEO to the *greatest* degree.⁷⁵

We approach this from a practical perspective, accepting that it is not possible to consider every permutation specifically. Where there are choices to be made among several plausible alternatives each of which would result in an overall decision that contributes to the achievement of the NEO, we have selected what we are satisfied would result in an overall decision that contributes to the achievement of the NEO to the greatest degree.

Also, in coming to this final decision we have considered Ergon Energy's initial and revised proposals. We have examined each of the building block components of the proposals and the incentive mechanisms that will apply across the next regulatory control period. We have considered the submissions we received in regard to Ergon Energy's proposals and our preliminary decision. We have conducted our own analysis and engaged expert consultant to help us better understand if and how Ergon Energy's proposals contribute to the achievement the NEO. We have also considered how our constituent decisions relate to each other, the impact that particular constituent decisions have on other constituent components of our decision, and have described these interrelationships in this final decision. We have undertaken an extensive and consultative regulatory review process to ensure we have canvassed stakeholder issues and made as much of this information publicly available as practicable. We have had regard to and weighed up all the information assembled before us in making this final decision.

Therefore, we are satisfied that among the options before us our final decision on Ergon Energy's distribution determination for the 2015–20 regulatory control period contributes to the achieving the NEO to the greatest degree.

5.1.1 Interrelationships between constituent components

Examining constituent components in isolation ignores the importance of the interrelationships between components of the overall decision, and would not contribute to the achievement of the NEO. As outlined by Energy Ministers, considering the elements in isolation has resulted in regulatory failures in the past.⁷⁶ Interrelationships can take various forms, including:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period (see attachment 6).

⁷⁵ NEL, s. 16(1)(d).

⁷⁶ SCER, *Regulation Impact Statement: Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks – Decision Paper*, 6 June 2013, p. 6.

- direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see attachments 3, 4 and 8).
- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa (see attachments 6 and 7).
- trade-offs between forecast and actual regulatory measures. The reasons for one part of a proposal may have impacts on other parts of a proposal. For example, an increase in augmentation to the network means the distributor has more assets to maintain leading to higher opex requirements (see attachments 6 and 7).
- the distributor's approach to managing its network. The distributor's governance arrangements and its approach to risk management will influence most aspects of the proposal, including capex/opex trade-offs (see attachment 6).

We have considered interrelationships, including those above, in our analysis of the constituent components of our final decision. These considerations are explored in the relevant attachments. We include a table of interrelationships, including the impacts of particular constituent decision on other constituent components of our distribution determination, in appendix D.

6 Ergon Energy's consultation

This section provides an overview and commentary on the consultation processes undertaken by Ergon Energy. Our specific assessment of the expenditure initiatives proposed by Ergon Energy arising from its stakeholder and consumer engagement can be found in the opex and capex assessments in attachments 6 and 7.

Ergon Energy developed a consumer engagement program (CEP) to assist it in developing its future investment plans.⁷⁷ A simplified form of the program is contained in figure 11.

Figure 11: Ergon Energy's engagement program for 2015–20 regulatory proposal

**PHASE 1:
INVITE STAKEHOLDERS TO BE INVOLVED AND BUILD ON ENGAGEMENT
(COMMENCED JULY 2013)**

The engagement program was launched at a stakeholder event in Townsville, with the approach and timeline outlined on our web site. Specific briefings then commenced with our Customer Council, as well as with regional community leaders.

**PHASE 2:
UNDERTAKE CUSTOMER RESEARCH (COMMENCED AUGUST 2013)**

Our existing research was reviewed, before a sophisticated service/cost trade-off research study was developed and undertaken. This allowed customer views across different segments and geographical areas to be actively considered in the development of the final proposal.

**PHASE 3:
VALIDATE OUR SERVICE COMMITMENTS AND DIRECTION OF INVESTMENT PLANS
(APRIL TO AUGUST 2014)**

Engagement activity was undertaken to validate the direction of the proposal, supported by the release of our refreshed service commitments, as well as our research findings and a range of other updates.

**PHASE 4:
PRESENT THE REGULATORY PROPOSAL (SEPTEMBER TO NOVEMBER 2014)**

Advanced presentation of the Regulatory Proposal was undertaken, allowing customers and other stakeholders to review and assess the key building blocks of our expenditure and the potential price impacts. This engagement is continuing. We are also encouraging participation in the AER's engagement activities through the final stages of the process.

Source: Ergon Energy, *Regulatory proposal, 0A.00.01 Overview*, October 2014, p. 5.

Ergon Energy submitted that it developed its program by looking at its customer base, considering their interests and what issues in the regulatory proposal they could genuinely inform.⁷⁸ Its program included direct customer engagement, sharing

⁷⁷ Ergon Energy, *Regulatory proposal, 0A.00.01 Overview*, October 2014, p. 5.

⁷⁸ Ergon Energy, *Regulatory proposal, 0A.01.04, Engagement program*, October 2014, p. 10.

information online and a customer research program.⁷⁹ Figure 12 outlines some of the engagement undertaken by Ergon Energy and what sections of its customer base were involved.

Figure 12: Overview of Ergon Energy’s engagement activities and customer base involved

250+ of our regional stakeholders, including 16 of our biggest business customers, were invited to give their views early in our investment planning process.

Listening sessions with **43 customers** gave us fresh insights into what our customers were thinking.

Engaging online has boosted involvement in the process. There were around **3,000 unique views** of the dedicated web pages and **80 people** gave feedback through our online stakeholder surveys.

Senior managers participated in around **40 forums** across the state, addressing in the order of 5,000 customers and building vital, ongoing relationships.

We asked **1,822 residents and 513 businesses** across regional Queensland how they would be willing to trade-off standards to help us bring electricity prices down.

Source: Ergon Energy, *Regulatory proposal, 0A.00.01 Overview*, October 2014..

Ergon Energy conducted additional consumer engagement in mid-2015 to explore customer views on our preliminary decision. It also did supplementary residential customer research at that time, assisted by Colmar Brunton.⁸⁰

Ergon Energy’s initial and revised regulatory proposals also form part of the consumer engagement process. The proposals enable stakeholders to engage in the review process through their submissions. The proposals represent a culmination of information and data to support Ergon Energy’s future service provision. Submissions we receive from stakeholders in response to the proposals are useful because they are informed by the detailed material contained in the proposals. The proposals are significantly more detailed (and refined) than the information provided before the proposals were submitted. According to Ergon Energy, its initial regulatory proposal

⁷⁹ Ergon Energy, *Regulatory proposal, 0A.01.04, Engagement program*, October 2014, p. 2.

⁸⁰ Ergon Energy, *SUB00.01, Submission to the AER’s preliminary decision*, July 2015, p. 8.

consisted of 8549 pages.⁸¹ Ergon Energy's revised regulatory proposal consisted of a further 18076 pages.⁸² Assessing all material presented to us is not just a matter of complying with the NER. It is good regulatory practice to consider the views of interested parties, and to consider the efficiency and prudence of Energex's proposal. Appendix B sets out our consultation in reaching our final decision.

6.1.1 NER requirements regarding consumer engagement

A number of the AEMC's 2012 rule changes attempt to address a lack of focus on consumer engagement and participation.⁸³ To achieve this, chapter 6 of the NER was amended to, among other things, require:

- distributors to submit an overview with their regulatory proposal which describes how they have engaged with consumers and sought to address any relevant concerns identified by that engagement.⁸⁴
- the AER to publish an issues paper after receiving the distributor's regulatory proposal.⁸⁵ The AEMC stated that the purpose of the issues paper would be to assist consumer representative groups to focus on the key preliminary issues on which they should engage and comment.⁸⁶
- the AER, when determining capex and opex allowances, to have regard to the extent to which the forecast includes expenditure to address the concerns of consumers as identified by the distributor in the course of its engagement with consumers.⁸⁷

The extent to which the proposed forecasts include expenditure to address the concerns of consumers during the course of its engagement with consumers is one of nine or more factors that we must have regard to in determining whether we are satisfied that the proposed capex (or opex) reasonably reflects the capex (or opex) criteria.⁸⁸ In this sense, the factor relating to consumer engagement alone is not determinative.

⁸¹ Ergon Energy, *Regulatory proposal, Confidentiality claims*, October 2014. Of the 8549 page regulatory proposal, 8301 pages were available publicly. The remaining 248 pages were subject to confidentiality claims.

⁸² Ergon Energy, *Revised regulatory proposal, Confidentiality claim*, July 2015. Of the 18076 page revised regulatory proposal, 17725 pages were available publicly. The remaining 351 pages were subject to confidentiality claims.

⁸³ AEMC, *Rule determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*.

⁸⁴ NER, cl. 6.8.2(c1)(2).

⁸⁵ NER, cl. 6.9.3(b). Although this step was not mandatory under the transitional arrangements applying in respect of Ergon Energy for the 2015–20 regulatory control period, the AER chose to publish an issues paper to assist stakeholders to understand and comments on Ergon Energy's initial regulatory proposal.

⁸⁶ AEMC, *Rule determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*.

⁸⁷ NER, cl. 6.5.6(e)(5A) and 6.5.7(e)(5A).

⁸⁸ NER, cl. 6.5.6(e)(5A) and 6.5.7(e)(5A).

6.1.2 Comments on Ergon Energy's consumer engagement

Our comments are based on the steps Ergon Energy has taken which reflect our expectations as set out in the Consumer Engagement Guideline for Network Service Providers, released in 2013.⁸⁹ The Consumer Engagement Guideline presents a framework for service providers to establish a consumer engagement strategy and to develop processes that best fit their business. We expect electricity and gas service providers to engage meaningfully with consumers as part of their usual way of doing business across a range of business activities. Importantly the Consumer Engagement Guideline sets expectations regarding network consumer engagement but does not seek compliance nor define how network businesses should engage with consumers.

With the NER requirements in mind and having regard to Ergon Energy's CEP, it is clear that Ergon Energy has attempted to reflect consumer issues and concerns in its regulatory proposal in line with best practice principles set out in our Guideline. Ergon Energy's efforts to engage with consumers have been commended by some stakeholders.⁹⁰ However, Ergon Energy's CEP is still developing. This was reflected in stakeholder submissions to Ergon Energy's regulatory proposal:

- Canegrowers submitted that while Ergon Energy's workshops provided insights into the proposal being prepared, they were not designed to enable participants to critically analyse the issues.⁹¹
- Queensland Council of Social Services (QCOSS) and the Chamber of Commerce and Industry Queensland acknowledged that Ergon Energy had attempted to engage but it was not evident where the views of those engaged have been reflected in the proposals submitted to the AER.⁹²
- QCOSS also submitted that Ergon Energy attempted to seek feedback on possible positions but was asking participants to provide responses without full information on price implications.⁹³
- Total Environment Centre submitted that Ergon Energy openly acknowledged the purpose of its engagement was to provide information rather than opportunities for stakeholder input into the development of its proposal.⁹⁴

The Chamber of Commerce and Industry Queensland and Regional Development Australia Far North Queensland and Torres Strait Inc. submitted that the volume and

⁸⁹ See our website for the guideline, <https://www.aer.gov.au/node/18894>.

⁹⁰ CCIQ, *Submission on Ergon Energy's regulatory proposal*, January 2015, p. 20; Total Environment Centre, *Submission on Energy and Ergon Energy regulatory proposals*, January 2015, p. 19; Townsville Enterprise, *Submission on Ergon Energy's regulatory proposal*, January 2015, p. 5.

⁹¹ Canegrowers, *Submission on Energex and Ergon Energy regulatory proposals*, January 2015, p. 6.

⁹² QCOSS, *Submission on Energex and Ergon Energy regulatory proposals*, January 2015, p. 14; CCIQ, *Submission on Ergon Energy's regulatory proposal*, January 2015, p. 20.

⁹³ QCOSS, *Submission on Energex and Ergon Energy regulatory proposals*, January 2015, p. 14.

⁹⁴ Total Environment Centre, *Submission on Energy and Ergon Energy regulatory proposals*, January 2015, p. 19.

technical nature of material Ergon Energy included in its regulatory proposal was a barrier to parties engaging with the proposal.⁹⁵

Our Consumer Engagement Guideline emphasises the need for engagement to be genuine. Fundamental to this is building a relationship with consumers and consumer representatives. While Ergon Energy's engagement strategy appears to be reasonably comprehensive and it has conducted a range of consultation, we could not see how Ergon Energy has measured the outcomes of its program and stakeholder feedback and applied that feedback to its strategy. We consider that Ergon Energy must continue working towards this. The outcome of engagement should be focussed on gaining an understanding of consumers and their needs in the lead up to developing a regulatory proposal and clearly reflecting those findings in its proposals. In this instance, based on stakeholder submissions, it appears that Ergon Energy has instead used its newly established consumer engagement process to inform consumers of a regulatory proposal that was likely well developed.

We expect that Ergon Energy's engagement with consumers will continue to develop over time. We also expect engagement with consumers to become more sophisticated, as will consumers' expectations of Ergon Energy, in working with consumers in developing its next regulatory proposal.

⁹⁵ CCIQ, *Submission on Ergon Energy's regulatory proposal*, January 2015, p. 20; Regional Development Australia FNQ and Torres Strait Inc., *Submission on Ergon Energy's regulatory proposal*, January 2015, p. 2.

A Constituent decisions

Our final distribution determination is predicated on the following decisions (constituent decisions).⁹⁶

Constituent decision

In accordance with clause 6.12.1(1) of the NER, the following classification of services will apply to Ergon Energy for the 2015–20 regulatory control period (listed by service group):

- Standard control services include network services, small customer connections and type 7 metering services
- Alternative control services include metering types 5 and 6 metering services, large customer connections, ancillary network services and public lighting
- Unregulated services include type 1 to 4 metering services and the Hayman Island undersea cable.

Attachment 13 discusses classification of services.

In accordance with clause 6.12.1(2)(i) of the NER, the AER does not approve the annual revenue requirement set out in Ergon Energy's building block proposal. Our final decision on Ergon Energy's annual revenue requirement for each year of the 2015–20 regulatory control period is set out in attachment 1 of the final decision.

In accordance with clause 6.12.1(2)(ii) of the NER, the AER approves Ergon Energy's proposal that the regulatory control period will commence on 1 July 2015. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER approves Ergon Energy's proposal that the length of the regulatory control period will be five years from 1 July 2015 to 30 June 2020.

In accordance with clause 6.12.1(3)(ii) and acting in accordance with clause 6.5.7(c), the AER does not accept Ergon Energy's proposed total forecast capital expenditure of \$3282.4 million (\$2014–15). Our substitute estimate of Ergon Energy's total forecast capex for the 2015–20 regulatory control period is \$2858.1 million (\$2014–15). This is discussed in attachment 6 of the final decision.

In accordance with clause 6.12.1(4)(ii) and acting in accordance with clause 6.5.6(d), the AER does not accept Ergon Energy's proposed total forecast operating expenditure inclusive of debt raising costs of \$1841.8 million (\$2014–15). Our final estimate of Ergon Energy's total forecast opex for the 2015–20 regulatory control period is \$1757.9 million (\$2014–15). This is discussed in attachment 7 of the final decision.

In accordance with clause 6.12.1(4A)(i) the AER determines that there are no contingent projects for the purposes of the distribution determination.

Ergon Energy did not include any proposed contingent projects in its regulatory proposal for the 2015–20 regulatory control period. Therefore,

- in accordance with clause 6.12.1(4A)(ii), the AER has not made an assessment of whether the capital expenditure proposed in the context of each contingent project reflects the capital expenditure criteria and factors
- in accordance with clause 6.12.1(4A)(iii), the AER does not specify any trigger events in relation to contingent projects
- in accordance with clause 6.12.1(4A)(iv), the AER does not determine that any proposed contingent project is not a contingent project.

In accordance with clause 6.12.1(5) the AER's decision on the allowed rate of return for the first regulatory year of the regulatory control period in accordance with clause 6.5.2 is not to accept Ergon Energy's revised proposal of 7.41 per cent. Our decision on the allowed rate of return for the first regulatory year of the regulatory control period is 6.01 per cent as set out in table 3.1 of attachment 3 of the final decision. This rate of return will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.

⁹⁶ NER, cl. 6.12.1.

Constituent decision

In accordance with clause 6.12.1(5A) the AER's decision is that the return on debt is to be estimated using a methodology referred to in clause 6.5.2(i)(2) which is set out in attachment 3 (appendix I) of the final decision.

In accordance with clause 6.12.1(5B) the AER's decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.4. This is set out in attachment 4 of the final decision.

In accordance with clause 6.12.1(6) the AER's decision on Ergon Energy's regulatory asset base as at 1 July 2015 in accordance with clause 6.5.1 and schedule 6.2 is \$9873 million (\$ nominal). This is set out in attachment 2 of the final decision.

In accordance with clause 6.12.1(7) the AER does not accept Ergon Energy's revised proposed corporate income tax of \$601.3 million (\$ nominal). Our decision on Ergon Energy's corporate income tax is \$179.6 million (\$ nominal). This is set out in attachment 8 of the final decision.

In accordance with clause 6.12.1(8) the AER's decision is not to approve the depreciation schedules submitted by Ergon Energy. This is set out in attachment 5 of the final decision.

In accordance with clause 6.12.1(9) the AER makes the following decisions on how any applicable efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme is to apply:

- In accordance with clause 6.12.1(9) of the NER, the AER's decision is to apply version two of the EBSS to Ergon Energy in the 2015–20 regulatory control period. This is set out in attachment 9 of the final decision.
- In accordance with clause 6.12.1(9) of the NER, we will apply the CESS as set out in version 1 of the Capital Expenditure Incentives Guideline to Ergon Energy in the 2015–20 regulatory control period. CESS is discussed in attachment 10 of the final decision.
- In accordance with clause 6.12.1(9) of the NER, we will apply our Service Target Performance Incentive Scheme (STPIS) to Ergon Energy for the 2015–20 regulatory control period. STPIS is discussed in attachment 11 of the final decision.
 - We will apply the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) reliability of supply parameters. We will also apply the customer service telephone answering parameter. We will not apply a guaranteed service level scheme as Ergon Energy must comply with its existing Queensland jurisdictional guaranteed service level scheme.
 - A beta of 2.5 will be used to calculate the major event day boundary.
 - Our decision on the SAIDI and SAIFI incentive rates and performance targets to apply to Ergon Energy for the 2015–20 regulatory control period are set out in tables 11.1 and 11.2 of attachment 11 of this final decision.
 - Our decision on the customer service incentive rate and performance target are set out in section 11.1 of attachment 11 of this final decision.
 - The revenue at risk for Ergon Energy will be capped at ± 2.0 per cent.

Note: The meaning for year "t" under the price control formula for this determination is different to that in Appendix C of STPIS. Year "t+1" in Appendix C of STPIS is equivalent to year "t" in the price control formula of this decision.

- The AER has determined to continue Part A of the Demand Management Innovation Scheme (DMIS) for Ergon Energy in the 2015–20 regulatory control period (that is, the DMIA component). DMIS is discussed in attachment 12 of the final decision.

In accordance with clause 6.12.1(10) the AER's decision is that all appropriate amounts, values and inputs are as set out in this determination including attachments.

In accordance with clause 6.12.1(11) the AER's decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for Ergon Energy for any given regulatory year is the total revenue (TAR) calculated using the formula in attachment 14 plus any adjustment required to move the DUoS under/over account to zero. This is discussed at attachment 14 of the final decision.

In accordance with clause 6.12.1(12) the AER's decision on the form of the control mechanism for alternative control services is to apply price caps. This is discussed in attachment 16 of the final decision.

Constituent decision

In accordance with clause 6.12.1(13), to demonstrate compliance with its distribution determination, the AER's decision is Ergon Energy must maintain a DUoS unders and overs account. It must provide information on this account to us in its annual pricing proposal. This is discussed in attachment 14 in the final decision.

In accordance with clause 6.12.1(14) the AER's decision on the additional pass through events that are to apply is to accept the nominated pass through events as proposed by Ergon Energy for:

- insurance cap event
- insurer's credit risk event.

The AER substitutes its own definition for:

- natural disaster event.

In accordance with clause 6.12.1(15) the AER's decision is to approve Ergon Energy's proposed negotiating framework. The negotiating framework that is to apply to Ergon Energy is set out at attachment 17 of the final decision.

In accordance with clause 6.12.1(16) the AER's decision is to apply the negotiated distribution services criteria published in November 2014 to Ergon Energy. This is set out is at attachment 17 of the final decision.

In accordance with clause 6.12.1(17) the AER's decision on the procedures for assigning retail customers to tariff classes for Ergon Energy is set out at attachment 14 of the final decision.

In accordance with clause 6.12.1(18) the AER's decision on regulatory depreciation is that the forecast depreciation approach is to be used to establish the RAB at the commencement of Ergon Energy's regulatory control period (1 July 2020). This is discussed in attachment 2 of the final decision.

In accordance with clause 6.12.1(19) the AER's decision on how Ergon Energy is to report to the AER on its recovery of designated pricing proposal charges is to set this out in its annual pricing proposal. The AER accepts Ergon Energy's proposed methodology to account for under and over recovery of charges. This is discussed in attachment 14 of the final decision.

In accordance with clause 6.12.1(20) the AER's decision is we require Ergon Energy to maintain a jurisdictional scheme unders and overs account. It must provide information on this account to us in its annual pricing proposal as set out in attachment 14 of the final decision.

In accordance with clause 6.12.1(21) the AER approves the connection policy submitted by Ergon Energy on 3 July 2015 in relation to its revised proposal. This is set out in attachment 18 of the final decision.

B Our consultation process

This section summarises our consultation and engagement with stakeholders, interested parties and Ergon Energy in coming to this final decision.

We recognise that stakeholder participation in decision making processes is an important element of achieving the NEO by better understanding the long term interests of consumers. The NEL requires us to inform stakeholders of the material issues we are considering and to give them a reasonable opportunity to make submissions in respect of the decision before it is made.⁹⁷

Below we set out the consultation process we have followed leading up to this final decision. We have considered the views presented to us at each stage in reaching our final decision.

Effective consultation with stakeholders is essential to the performance of our regulatory functions. In summary, our consultation and engagement with stakeholders through the process that has led to this final determination can be summarised as follows:

- holding regular meetings with Ergon Energy to discuss issues relevant to this decision. These meetings commenced in May 2013 to discuss the framework and approach. The meetings continued throughout our decision making process.
- establishing the CCP to assist us to make better regulatory determinations by providing input on issues of importance to consumers
- publishing an issues paper to help stakeholders engage with, and meaningfully respond to issues in Ergon Energy's regulatory proposal that we considered material to consumers
- hosting public forums in Brisbane on 9 December 2014 and 12 May 2015 so stakeholders could question the AER, the CCP and Ergon Energy on its regulatory proposal
- having Ergon Energy present its regulatory proposal to the AER Board on 16 January 2015 and its revised proposal on 10 July 2015, so questions could be raised and key issues explained
- having the CCP present its advice in response to Ergon Energy's initial and revised regulatory proposals and our preliminary decision to the AER Board
- considering 33 submissions on Ergon Energy's regulatory proposal and a total of 30 submissions on our preliminary decision and Energex's revised proposal. A list of the latter submissions is at appendix C.
- convening monthly meetings between the CCP and AER staff to discuss key issues

⁹⁷ NEL, s. 16 (1)(b).

- ongoing formal and informal jurisdictional consumer forums from November 2013
- consulting on benchmarking measures prepared by us and Economic Insights, jointly relevant to the preparation of the annual benchmarking report and our assessment of Ergon Energy's initial regulatory proposal
- having ongoing discussions with Ergon Energy about its initial and revised regulatory proposals. In particular, our consultants and AER staff met with Ergon Energy to discuss opex, augex and repex. During this process, AER staff and our consultants considered over 100 responses to information requested from Ergon Energy.
- releasing a brief consultation paper on recovering the residual metering capital costs through an alternative control service charge and considering 19 submissions in response.

This process builds on the extensive consultation undertaken by the AER as part of the Better Regulation program. Following the 2012 changes to the NER, we spent much of 2013 consulting on and refining our assessment methods and approaches to decision making. We referred to this as our Better Regulation program. The objective of this program was to refine our approaches, with a greater emphasis on incentive regulation. The Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged and provide their input.

The resulting Guidelines support our decision making framework as set out in section 16 of the NEL. Our consultation and engagement gives us confidence the approaches set out in the Guidelines, which we have applied in this decision, will result in decisions that will or are likely to contribute to the achievement of the NEO to the greatest degree. Our Better Regulation Guidelines are available on our website and include:

- Expenditure Forecast Assessment Guideline
- Expenditure Incentives Guideline
- Rate of Return Guideline
- Consumer Engagement Guideline for Network Service Providers
- Shared Assets Guideline
- Confidentiality Guideline.

Our consultation processes, which go well beyond the minimum requirements of the NER, provide us with a range of stakeholder views.

C List of submissions

We received 30 submissions in response to Ergon Energy's revised regulatory proposal and our preliminary decision as listed below:

	Submission from	Date received	Submission on
1	Alliance of Electricity Consumers	3 July 2015	AER preliminary decision
2	AusNet Services	3 July 2015	AER preliminary decision
3	Canegrowers	7 July 2015	AER preliminary decision
4	Chamber of Commerce and Industry Qld	3 July 2015	AER preliminary decision
5	Cotton Australia	2 July 2015	AER preliminary decision
6	Energy Retailer's Association of Australia	3 July 2015	AER preliminary decision
7	Far North Qld Regional Organisation of Councils	3 July 2015	AER preliminary decision
8	Lendlease	18 June 2015	AER preliminary decision
9	Origin	3 July 2015	AER preliminary decision
10	Professionals Australia	2 July 2015	AER preliminary decision
11	Qld Council of Social Services	3 July 2015	AER preliminary decision
12	Qld Consumers' Association	3 July 2015	AER preliminary decision
13	Qld Farmers' Federation	3 July 2015	AER preliminary decision
14	Qld Resources Council	3 July 2015	AER preliminary decision
15	Robin Russell & Associates	3 July 2015	AER preliminary decision
16	SPA Consulting	3 July 2015	AER preliminary decision
17	Total Environment Centre	3 July 2015	AER preliminary decision
18	United Energy	3 July 2015	AER preliminary decision
19	Vector Limited	3 July 2015	AER preliminary decision
20	Alliance of Electricity Consumers	24 July 2015	Ergon Energy and Energex's revised proposals
21	CitiPower and Powercor	24 July 2015	Current regulatory determination processes
22	Cotton Australia	24 July 2015	Ergon Energy and Energex's revised proposals
23	Ergon Energy	24 July 2015	Ergon Energy's revised proposal
24	Far North Qld Electricity Users Network	24 July 2015	Ergon Energy's revised proposal
25	Local Government Association of Qld	24 July 2015	Ergon Energy and Energex's revised proposals
26	Jemena	24 July 2015	Current regulatory determination processes

	Submission from	Date received	Submission on
27	Multinet Gas	24 July 2015	Current regulatory determination processes
28	Qld Farmers' Federation	24 July 2015	Ergon Energy's revised proposal
29	Qld Resources Council	24 July 2015	Ergon Energy's revised proposal
30	United Energy	24 July 2015	Current regulatory determination processes

D Interrelationships in the AER’s final decision for Ergon Energy

Interrelationships in the AER’s final decision for Ergon Energy

Page Ref.	Explanation
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Overview

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Examining constituent components in isolation ignores the importance of the interrelationships between components of the overall decision, and would not contribute to the achievement of the NEO. As outlined by Energy Ministers, considering the elements in isolation has resulted in regulatory failures in the past. Interrelationships can take various forms, including:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period (see attachment 6).
- direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark efficient entity’s debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see attachments 3, 4 and 8).
- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa (see attachments 6 and 7).
- trade-offs between forecast and actual regulatory measures. The reasons for one part of a proposal may have impacts on other parts of a proposal. For example, an increase in augmentation to the network means the network service provider has more assets to maintain leading to higher opex requirements (see attachments 6 and 7).
- the network service provider’s approach to managing its network. The network service provider’s governance arrangements and its approach to risk management will influence most aspects of the proposal, including capex/opex trade-offs (see attachment 6).

We have considered interrelationships, including those above, in our analysis of the constituent components of our final decision. These considerations are explored in the relevant attachments.

Attachment 1: Annual Revenue Requirement

Smoothing profile (X factors) is affected by the overall annual revenue requirement based on all building block decisions, including rate of return and capex. Further, the smoothing profile is affected by the removal of alternative control services assets for changes in classification of services.

Attachment 2: Regulatory asset base

Interrelationships in the AER's final decision for Ergon Energy

The RAB is an input into the determination of the return on capital and depreciation (return of capital) building block allowances. Factors that influence the RAB will therefore flow through to these building block components and the annual revenue requirement. Other things being equal, a higher RAB increases both the return on capital and depreciation allowances.

The RAB is determined by various factors, including:

- the opening RAB (meaning the value of existing assets at the beginning of the regulatory control period)
- net capex
- depreciation
- indexation adjustment – so the RAB is presented in nominal terms, consistent with the rate of return.

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p. 2–11

The opening RAB depends on the value of existing assets and will depend on actual net capex, actual inflation outcomes and depreciation in the past.

The RAB when projected to the end of the regulatory control period increases due to both forecast new capex and the indexation adjustment. The size of the indexation adjustment depends on expected inflation (which also affects the nominal rate of return) and the size of the RAB at the start of each year.

Depreciation reduces the RAB. The depreciation allowance depends on the size of the opening RAB and the forecast net capex. By convention, the indexation adjustment is also offset against depreciation to prevent double counting of inflation in the RAB and rate of return, which are both presented in nominal terms. This reduces the apparent depreciation building block that feeds into the annual revenue requirement.

Maintaining the RAB in real terms by adding inflation is required by the NER and generally helps to promote smoother prices over the life of an asset. If the RAB was unindexed for inflation, the offsetting indexation adjustment applied to depreciation would also have to be removed. On balance, this means more depreciation would be returned to the business resulting in higher prices early in an asset life and lower prices later in its life. Even if allowed under the NER, moving to an unindexed RAB would lead to a price increase over the short to medium term and when new lumpy assets are added to the RAB.

The depreciation amount also largely depends on the opening RAB (which in turn depends on capex in the past).

Attachment 3: Rate of return

This section notes the key interrelationships in the rate of return decision in the context of the rule requirements to apply a rate of return. Where we have had regard to these in developing our approach, they are more fully described in the Guideline. The manner in which these are taken into account in making this decision is set out as part of our reasoning and analysis in section 3.4 and the rate of return appendices.

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We estimate a rate of return for a benchmark efficient entity which is then applied to a specific service provider rather than determining the returns of a specific service provider based on its specific circumstances. This is the same whether estimating the return on equity or return on debt as separate components. We set a rate of return that is commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as the service provider in respect of the provision of standard control services. This provides a reasonable opportunity to recover at least the efficient costs. The network service provider's actual returns could be higher or lower compared to the benchmark depending on how efficiently it operates its business. This is consistent with incentive regulation. That is, our rate of return approach drives efficient outcomes by creating the correct incentive by allowing network service providers to retain (fund) any additional income (costs) by outperforming

(underperforming) the efficient benchmark.

We are mindful that we apply a benchmark approach and an incentive regulatory framework. Any one component or relevant parameter adopted for estimating the rate of return should not be solely viewed in isolation. In developing our approach and implementing it to derive the overall rate of return we are cognisant of a number of interrelationships relating to the estimation of the return on equity and debt and underlying input parameters.

Single benchmark

We adopt a single benchmark efficient entity across all service providers. In deciding on a single benchmark we considered different types of risks and different risk drivers that may have the potential to lead to different risk exposures. We also noted that the rate of return compensates investors only for non-diversifiable risks (systematic risks) and other types of risks are compensated via cash flows and some may not be compensated at all. These interrelationships between the types of risk and the required compensation via the rate of return are an important factor. Our view is that the benchmark efficient entity would face a similar degree of risk irrespective of the:

- energy type (gas or electricity)
- network type (distribution or transmission)
- ownership type (government or private)
- size of the service provider (big or small).

Domestic market

We adopt the Australian market as the market within which the benchmark efficient entity operates. This recognises that the location of a business determines the conditions under which the business operates and these include the regulatory regime, tax laws, industry structure and broader economic environment. As most of these conditions will be different from those prevailing for overseas entities, the risk profile of overseas entities is likely to differ from those within Australia. Consequently, the returns required are also likely to differ. This is an important factor in estimating the rate of return and we therefore adopt a domestic approach. Hence, when estimating input parameters for the Sharpe–Lintner capital asset pricing model (SLCAPM) we place most reliance on Australian market data whilst, using overseas data informatively.

Benchmark gearing

We apply a benchmark efficient level of gearing of 60 per cent. This benchmark gearing level is used:

- to weight the expected required return on debt and equity to derive the overall rate of return using the WACC formula
- to re-lever asset betas for the purposes of comparing the levels of systematic risk across businesses which is relevant for the equity beta estimate.

We adopt a benchmark credit rating which is BBB+ or its equivalent for the purposes of estimating the return on debt. To derive this benchmark rating and the gearing ratio, we reviewed a sample of regulated networks. Amongst a number of other factors, a regulated service provider's actual gearing levels have a direct relationship to its credit ratings. Hence, our findings on the benchmark gearing ratio of 60 per cent and the benchmark credit rating are interrelated given that the underlying evidence is derived from a sample of regulated network service providers.

Interrelationships in the AER's final decision for Ergon Energy

Term of the rate of return

We adopt a 10 year term for our overall rate of return. This results in the following economic interdependencies that impact on the implementation of our return on equity and debt estimation methods:

- The risk free rate used for estimating the return on equity is a 10 year forward looking rate
- The market risk premium (MRP) estimate is for a 10 year forward looking period
- We adopt a 10 year debt term for estimating the return on debt.

Attachment 4: Value of imputation credits

Preliminary decision
p. 4–13

The NER recognise that a service provider's allowed revenue does not need to include the value of imputation credits. The NER adjust for the value of imputation credits via the revenue granted to a service provider to cover its expected tax liability. This form of adjustment recognises that it is the payment of corporate tax which is the source of the imputation credit return to investors.

The value of imputation credits is also interrelated with the MRP. As discussed in attachment 3, the definition of the MRP in the SLCAPM should account for the capitalised value of imputation credits. Accordingly, in our determination of the return on equity in attachment 3 we adjust estimates of the MRP in a manner consistent with our determination of the value of imputation credits in this attachment. This is also required by the NER/NGR.

Attachment 5: Regulatory depreciation

Preliminary decision
p. 5–9

The regulatory depreciation allowance is a building block component of the annual revenue requirement. Higher (or quicker) depreciation leads to higher revenues over the regulatory control period. It also causes the RAB to reduce more quickly (assuming no further capex). This outcome reduces the return on capital allowance, although this impact is usually secondary to the increased depreciation allowance.

Ultimately, however, a service provider can recover only once the capex that it incurred on assets. The depreciation allowance reflects how quickly the RAB is being recovered, and it is based on the remaining and standard asset lives used in the depreciation calculation. It also depends on the level of the opening RAB and the forecast capex. Any increase in these factors also increases the depreciation allowance.

To prevent double counting of inflation through the WACC and the RAB, the regulatory depreciation allowance also has an offsetting reduction for indexation of the RAB. Factors that affect forecast inflation and/or the size of the RAB will affect the size of this indexation adjustment.

Attachment 6: Capital expenditure

Interrelationships in the AER's final decision for Ergon Energy

There are a number of interrelationships between total forecast capex and other components of the distribution. We considered these interrelationships in coming to our final decision on total forecast capex.

Capex and opex

Elements of total forecast opex relate to total forecast capex. These include the forecast labour price growth included in our opex forecast. The price of labour affects both total forecast capex and total forecast opex.

More generally, our total opex forecast will provide sufficient opex to maintain network reliability. Although we do not approve opex on specific opex categories such as maintenance, the total opex we approve will in part influence the required repex.

Capex and demand

Forecast demand is related to total forecast capex. Growth driven capex, which includes augex and customer connections capex, is typically triggered by a need to build or upgrade a network to address changes in demand or to comply with quality, reliability and security of supply requirements. Hence, the main driver of growth-related capex is maximum demand and its effect on network utilisation and reliability.

Capex and CESS

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The CESS is related to total forecast capex. In particular, the effective application of the CESS is contingent on the approved total forecast capex being efficient and that it reasonably reflects the capex criteria. As we note in the capex criteria table below, this is because any efficiency gains or losses are measured against the approved total forecast capex. In addition, in future distribution determinations we will be required to undertake an ex post review of the efficiency and prudence of capex, with the option to exclude any inefficient capex in excess of the approved total forecast capex from the network service provider regulatory asset base. In particular, the CESS will ensure that the network service provider bears at least 30 per cent of any overspend against the capex allowance. Similarly, if the network service provider can fulfil their objectives without spending the full capex allowance, it will be able to retain 30 per cent of the benefit of this. In addition, if an overspend is found to be inefficient through the ex post review, the network service provider risks having to bear the entire overspend.

Capex and STPIS

The STPIS is interrelated to the total forecast capex, in so far as it is important that it does not include any expenditure for the purposes of improving supply reliability during the regulatory control period. This is because such expenditure should be offset by rewards provided through the application of the STPIS.

Further, the forecast capex should be sufficient to maintain performance at the targets set under the STPIS. The capex allowance should not be set such that there is an expectation that it will lead to the network service provider systematically under or over performing against its targets.

Capex and contingent projects

A contingent project is interrelated to total forecast capex. This is because an amount of expenditure that should be included as a contingent project should not be included as part of the total forecast capex.

Attachment 7: Operating expenditure

Interrelationships in the AER's final decision for Ergon Energy

In assessing total forecast opex we take into account other components of the regulatory proposal, including:

- The impact of cost drivers that affect both forecast opex and forecast capex. For instance forecast maximum demand affects forecast augmentation capex and forecast output growth used in estimating the rate of change in opex.
- The inter-relationship between the RAB and opex.
- The approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block.
- Changes to the classification of services from standard control services to alternative control services.
- Consistency with the application of incentive schemes.
- Concerns of electricity consumers.

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Attachment 8: Corporate income tax

The cost of corporate income tax building block feeds directly into the annual revenue requirement (ARR). This allowance is determined by four factors:

- pre-tax revenues
- tax expenses (including tax depreciation)
- the corporate tax rate
- gamma—the expected proportion of company tax that is returned to investors through the utilisation of imputation credits—which is offset against the corporate income tax allowance. This is discussed further at attachment 4.

Of these four factors, the corporate tax rate is set externally by the Government. The higher the tax rate the higher the required tax allowance.

The pre-tax revenues depend on all the building block components. Any factor that affects revenue will therefore affect pre-tax revenues. Higher pre-tax revenues can increase the tax allowance. Depending on the source of the revenue increase, the tax increase may be equal to or less than proportional to the company tax rate.

The tax expenses (or deductions) depend on various building block components and their size. Some components give rise to tax expenses, such as opex, interest payments and tax depreciation of assets. However, others do not, such as increases in return on equity. Higher tax expenses offset revenues as deductions in the tax calculation and therefore reduce the cost of corporate income tax allowance (all things being equal). Tax expenses include:

- Interest on debt – Interest is a tax offset. The size of this offset depends on the ratio of debt to equity and therefore the proportion of the RAB funded through debt. It also depends on the allowed return on debt and the size of the RAB.
- General expenses – In the main these expenses will match the opex allowance.
- Tax depreciation – A separate tax asset base (TAB) is maintained for the businesses reflecting tax rules. This TAB is affected by many of the same factors as the

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RAB, such as capex, although unlike the RAB value it is maintained at its historical cost with no indexation.

The TAB is also affected by the depreciation rate and asset lives assigned for tax depreciation purposes. A 10 per cent increase in the corporate income tax allowance causes revenues to increase by about 0.7 per cent. The proposed gamma of 0.25, compared to the value in our preliminary decision of 0.40, would increase the corporate income tax allowance by 32.3 per cent and total revenues by about 1.2 per cent.

Attachment 9: Efficiency benefit sharing scheme (EBSS)

The EBSS is intrinsically linked to a revealed cost forecasting approach for opex. Under this forecasting approach, the EBSS has two specific functions:

- To mitigate the incentive for a service provider to increase opex in the expected 'base year' to increase its approved opex forecast for the following regulatory control period.
- To provide a continuous incentive for a service provider to make efficiency gains - network service providers receive the same reward for an underspend and the same penalty for an overspend in each year of the regulatory control period.

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Incentives to reduce opex may also affect a service provider's incentives to undertake capex. We take into account these interactions in developing and implementing the EBSS as well as developing the capital expenditure sharing scheme (CESS). For instance:

- in developing and implementing the EBSS, we must have regard to any incentives that network service providers may have to capitalise operating expenditure as well as the possible effects of the scheme on incentives for the implementation of non-network alternatives.
- in developing the CESS, we must take into account the interaction of the scheme with other incentives that network service providers may have in relation to undertaking efficient opex or capex as well as the capex objectives and, if relevant, the opex objectives.

Attachment 10: Capital expenditure sharing scheme (CESS)

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The CESS relates to other incentives to incur efficient opex, conduct demand management, and maintain or improve service levels. We aim to incentivise network service providers to make efficient decisions on when and what type of expenditure to incur, and to balance expenditure efficiencies with service quality.

Attachment 11: Service target performance incentive scheme

In applying the STPIS we must consider any other incentives available to the network service provider under the NER or relevant distribution determination. One of the objectives of the STPIS is to ensure that the incentives are sufficient to offset any financial incentives the network service provider may have to reduce costs at the expense of service levels. The STPIS interacts with the Capital Expenditure Sharing Scheme (CESS) and the opex Expenditure Benefit Sharing Scheme (EBSS).

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The rewards and penalties amounts under STPIS (the incentive rates) are determined based on the average customer value for the improvement, or otherwise, to supply reliability (the VCR). This is aimed at ensuring that the network service provider's operational and investment strategies are consistent with customers' value for the services that are offered to them.

Our capex and opex allowances are set to reasonably reflect the expenditures required by a prudent and efficient business to achieve the capex and opex objectives.

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These include complying with all applicable regulatory obligations and requirements and, in the absence of such obligations, maintaining quality, reliability, and security outcomes.

The STPIS, on the other hand provides, an incentive for network service providers to invest in further reliability improvements (via additional STPIS rewards) where customers are willing to pay for it. Conversely, the STPIS penalises network service providers where they let reliability deteriorate. Importantly, the network service provider will only receive a financial reward after actual improvements are delivered to the customers.

In conjunction with CESS and EBSS, the STPIS will ensure that:

- any additional investments to improve reliability are based on prudent economic decisions
- reductions in capex and/or opex are achieved efficiently, rather than at the expense of service levels to customers.

Attachment 12: Demand management incentive scheme

We have regard to several factors and interrelationships in developing and implementing a DMIS. These are:

Benefits to consumers

- the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme
- the willingness of customers or end users to pay for increases in costs resulting from implementing DMIS.

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Balanced incentives

- the effect of a particular control mechanism (i.e. price as distinct from revenue regulation) on a distributor's incentives to adopt or implement efficient non-network alternatives
- the effect of classification of services on a distributor's incentive to adopt or implement efficient embedded generator connections
- the extent the distributor is able to offer efficient pricing structures
- the possible interactions between DMIS and other incentive schemes.

Attachment 13: Classification of services

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In assessing what services we classify, we are setting the basis for the charges that can be levied on those services. To allow charges to be recovered for standard control services, assets associated with delivering those services are added to the regulatory asset base (RAB). A separate RAB may also be constructed for the capital costs associated with an alternative control service. There will usually be operating costs associated with the provision of a service as well.

The assets that make up the RAB and the operating costs that relate to any standard control service form a starting point for our assessment of the distributor's proposal for recovering revenues through charges for their services. Classification of services will therefore influence all revenue components of our decision.

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There are assets and operating costs associated with the services provided by distributors. We set the revenues the distributor may collect from customers to recover their asset and operating costs. That revenue is recovered through tariffs the distributor develops to charge to its customers. The regulatory regime establishes incentives such as the Efficiency Benefit Sharing Scheme (EBSS) and the Capital Expenditure Sharing Scheme (CESS) to encourage the provision of services as efficiently as possible. All of these factors interrelate with each other. We must be cognisant of these interrelationships when we make our determinations.

The incentive schemes do not apply to services classified alternative control. As such, classifying services alternative control from standard control means the incentive schemes are no longer applied to expenditure associated with these services.

Attachment 14: Control mechanism

We considered the interrelationship between the control mechanism pass through amounts and the reclassification of metering services as alternative control services.

Attachment 15: Pass through events

Final decision p. 15–10 Nominated pass through events are interrelated with the opex and capex forecasts. These interrelationships require us to balance a decision to accept nominated pass through events with the need to maintain appropriate incentives in other aspects of the decision.

Attachment 16: Alternative control services

Final decision p. 16–30 We apply the same rate of return parameters for all direct control services (standard and alternative control services).
Our decision on alternative control services therefore interrelates with our decision on rate of return and imputation credits. Please refer to Attachments 3 and 4 for the WACC and gamma values we accept for direct control services, along with our reasons.