



Ausgrid
Endeavour Energy
Essential Energy
ActewAGL

Transitional distribution decision
2014–15

April 2014

© Commonwealth of Australia 2014

This work is copyright. Apart from any use permitted by the Copyright Act 1968, no part may be reproduced without permission of the Australian Competition and Consumer Commission. Requests and inquiries concerning reproduction and rights should be addressed to the Director Publishing, Australian Competition and Consumer Commission, GPO Box 3131, Canberra ACT 2601.

Inquiries about this document should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001
Tel: (03) 9290 1444
Fax: (03) 9290 1457
Email: AERInquiry@aer.gov.au

AER reference: 52294, 52254

Contents

Contents.....	i
Shortened forms	iii
Part 1 – AER’s decision	1
1 Overview	2
2 About this review	10
2.1 Overview of the NSW/ACT DNSPs	10
2.2 Review process	10
3 AER's approach	13
3.1 Assessment criteria	13
3.2 Assessment approach	14
4 Revenues for the transitional year	16
4.1 Annual revenue requirement for transitional year	16
4.2 Key components and drivers of the annual revenue requirement.....	33
5 Other constituent decisions	46
5.1 D-factor scheme and the Demand Management and Embedded Generation Connection and Incentive Scheme	46
5.2 Efficiency Benefit Sharing Scheme	47
5.3 Service Target Performance Incentive Scheme	49
5.4 Capital expenditure sharing scheme	49
5.5 Small-scale incentive scheme	49
5.6 Dual function assets	50
5.7 Classification of services	50
5.8 Cost pass throughs.....	52
5.9 Connection policies.....	53
Part 2 – Appendices	58
A Submissions.....	59
B Summary of the NSW/ACT DNSPs’ transitional regulatory proposals	61
B.1 Ausgrid.....	62
B.2 Essential Energy	70
B.3 Endeavour Energy	75
B.4 ActewAGL.....	80

This page has been left blank intentionally

Shortened forms

Shortened form	Extended form
ActewAGL	ActewAGL Distribution
AER	Australian Energy Regulator
capex	capital expenditure
CCP	Consumer Challenge Panel
CCP subpanel	the CCP subpanel formed for the NSW/ACT electricity distribution determinations
CESS	Capital expenditure sharing scheme
CPI	consumer price index
DMEGCIS	demand management and embedded generation connection incentive scheme
DNSP	distribution network service provider
DUOS	distribution use of system
EBSS	efficiency benefit sharing scheme
NEL	National Electricity Law
NER	National Electricity Rules
NSW/ACT DNSPs	ActewAGL, Ausgrid, Endeavour Energy and Essential Energy
opex	operating expenditure
PTRM	post tax revenue model
RAB	regulatory asset base
STPIS	service target performance incentive scheme
TNSP	transmission network service provider
TRP	transitional revenue proposal
TUOS	transmission use of system
WACC	weighted average cost of capital

Part 1 – AER’s decision

1 Overview

AER decision

We do not approve the revenues proposed by ActewAGL Distribution (ActewAGL), Ausgrid, Endeavour Energy, or Essential Energy, the NSW/ACT distribution network service providers (DNSPs), as set out in their transitional revenue proposals. We are not satisfied that recovery of the proposed revenues by Ausgrid, Endeavour Energy, Essential Energy or ActewAGL are reasonably likely to minimise variations in prices between the:

- current regulatory control period (1 July 2009 to 30 June 2014)
- transitional regulatory control period (1 July 2014 to 30 June 2015)
- subsequent regulatory control period (1 July 2015 to 30 June 2019)
- the regulatory years of the subsequent regulatory control period (the **price variation test**).

In applying the price variation test, we consider that the revenue proposals by Ausgrid, Endeavour Energy, Essential Energy and ActewAGL are not likely to contribute to the achievement of the National Electricity Objective (NEO). We consider they are not consistent with the revenue and pricing principles (RPPs) in the National Electricity Law (NEL) in terms of promoting efficient investment.¹

Instead we have approved a lower placeholder annual revenue requirement for the transitional regulatory control period for Ausgrid, Endeavour Energy, Essential Energy and ActewAGL. We are satisfied this alternative revenue allowance is more likely to minimise variations in prices across the relevant periods and years. Our reasons for this view are set out in this document. Our decisions on the other components of the determinations are also set out in this document.

In our determination, we have:

- passed through to customers the benefits of the NSW DNSPs spending less than their allowances for capital expenditure (because growth in demand was less than forecast) in the current regulatory control period
- rejected the NSW/ACT DNSPs' proposals for cost of capital and substituted our own estimate of cost of capital based on the methodology in our 2013 Guideline
- for this placeholder decision, adopted the forecast capital and operating expenditure estimates of the NSW/ACT DNSPs, which will be subject to detailed scrutiny when we receive the regulatory proposals.

Our role

We, the Australian Energy Regulator (AER), are responsible for regulating the revenues of DNSPs and transmission network service providers (TNSPs) operating in the National Electricity Market (NEM). The NEL and the National Electricity Rules (NER) provide the overarching framework under which we operate.

¹ NEL, s 16(1)(a) and (2)(a).

In November 2012, the Australian Energy Market Commission (AEMC) introduced major changes to the economic regulation of DNSPs and TNSPs under chapters 6 and 6A respectively of the NER.²

Prior to the making of the new rules, distribution determinations for the NSW/ACT DNSPs were due to commence on 1 July 2014 and would apply for a period of five years. However, to allow for an expedited transition to the new rules, the transitional rules adopt a two stage approach for the regulation of these DNSPs over the next five years:³

- the transitional regulatory control period
- the subsequent regulatory control period.

The AER is required to make a placeholder determination for the transitional regulatory control period by 30 April 2014, which will only apply for one year for the NSW/ACT DNSPs. One of the decisions we must make in this determination is whether to approve the DNSPs' proposed placeholder annual revenue requirement for the transitional regulatory control period. The AER will then carry out a full regulatory determination process by 30 April 2015 to apply to the subsequent regulatory control period. If the revenue approved in the full regulatory determination for the transitional regulatory control period is different to our placeholder determination then a true-up will apply.

This placeholder determination is not the usual complete determination that we are required to make under chapter 6 of the NER. We are, however, required to make various decisions for this one year regulatory control period. The decisions that the AER must make for the placeholder determination are set out in our determination documents.

One of these decisions relates to the annual revenue requirement for the transitional year. We may only approve a DNSP's proposed annual revenue requirement for the transitional year if we are satisfied that the amount is such that the recovery of it by the DNSP is reasonably likely to minimise variations in prices between the relevant regulatory control periods and years, as outlined above (referred to as the price variation test).⁴

Our decision must take into account the RPPs in the NEL and we must perform our function in a manner that will or is likely to contribute to the achievement of the NEO.⁵ Importantly, the price variation test is centred on reducing the potential for any future significant price changes for consumers.

Where relevant, we have set out the manner in which the constituent components of the decision relate to each other in our reasons. We have indicated the manner in which that interrelationship has been taken into account in our decision.

In this determination we have made the decision that we are satisfied would, or is likely to contribute to the achievement of the NEO to the greatest degree, and we have included our reasons as to why we are satisfied that our decision is the preferable decision.⁶

² AEMC Final Rule Determination, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012 (AEMC Final Rule Determination).

³ NER, Chapter 11, Savings and Transitional Rules, Part ZW Economic Regulation of Network Service Providers (2012 amendments).

⁴ NER, cl 11.56.3(b).

⁵ NEL, s 16(1)(a) and (2)(a).

⁶ NEL, s 16. Section 16 provides that the AER must perform or exercise its function or power in a manner that will or is likely to contribute to the achievement of the NEO and further, if the function or power relates to the making of, relevantly, a distribution determination, ensure, amongst other matters, that where there are two or more possible reviewable

Transitional year review process

The transitional regulatory proposals (TRPs) were submitted to us on 31 January 2014 and we are required to publish our placeholder determination by 30 April 2014. This has been intentionally designed as a streamlined process, with no draft decision as would normally be the case with our regulatory determinations. Consistent with this approach, the consultation period we were required to undertake for the placeholder determination is shorter than the consultation undertaken for a full determination. Submissions on the TRPs closed on 3 March 2014.

The NSW/ACT DNSPs were required to submit an indicative range of revenue requirements and other relevant information for the purposes of this placeholder determination.⁷ We are required to make a high level assessment of the proposed revenue estimate, having regard to the fact that it is an estimate based on indicative inputs and that any adjustments will be made to the annual revenue requirement in the subsequent regulatory control period. Importantly, we are not required to make a determination based on a detailed assessment of the building block methodology.

Our approach

Our decision to approve or not approve the proposed annual revenue requirement for the transitional regulatory control period requires us to form a view about the expected movement of prices not just for the transitional year but from 2013 to 2014, 2014 to 2015 and so on until 2019. This view in turn must necessarily reflect our expectations of future revenues and demand.

Our expectations of future revenues are based on our assessment of the information currently available to us which includes indicative estimates or ranges of key inputs as submitted by the NSW/ACT DNSPs.

In considering the various inputs used to calculate prices, we have largely relied upon the indicative inputs provided by the NSW/ACT DNSPs to support their proposals. We have had regard to the fact that our determination of revenue is an estimate only. An adjustment will be made to future revenue requirements in accordance with the transitional rules to account for the revenue we approve in this transitional year. In the absence of detailed information about particular building blocks, we are generally not able to undertake the rigorous kind of analysis that would be required to be satisfied that the NSW/ACT DNSPs' indicative inputs are accurate or inaccurate.

Nevertheless, while we have used most of the inputs provided by NSW/ACT DNSPs in making our assessment, we have paid particular attention to the indicative rate of return and 'tax imputation credits' (gamma) proposed by the NSW/ACT DNSPs in support of their proposals. Given the significance of the rate of return in calculating revenue, small changes in the rate of return can have significant implications for prices. If the NSW/ACT DNSPs have proposed a rate of return that we consider is likely to be too high, proposed prices, based on the energy forecasts provided by NSW/ACT DNSPs, will also be too high.

In considering a reasonable indicative rate of return, we have had regard to the proposals, to our own guideline, to available market information and expected market trends, and are aware that the rate of return is subject to movement. After making an appropriate adjustment to the rate of return and to the

⁷ regulatory decisions that will or are likely to contribute to the achievement of the NEO, make the decision that the AER is satisfied will or is likely to do so to the greatest degree (the preferable reviewable regulatory decision).
NER, clause 11.56.2(b).

value of imputation credits (γ)⁸ used to support the NSW/ACT DNSPs' proposals, we then consider the transitional revenue proposals in the context of the price variation test taking into account the NEO and RPPs.

We consider this approach should not, in any way, be taken as an indication of our assessment of the full proposals in which a true-up of revenue for the transitional regulatory control period will be conducted. The approach and conclusions in this determination are purely for the purposes of making the required assessment we must make for this transitional regulatory control period under the transitional rules.

AER reasons

Our reasons for not accepting the TRPs are summarised below. We have assessed whether the proposals are likely to satisfy the price variation test by considering key inputs into the proposed indicative ranges for the annual revenue requirement. In particular, we have focused on the rate of return element in the annual revenue requirement in the context of whether the proposals are likely to minimise variations in distribution prices over the relevant regulatory control periods and years. In line with the price variation test, this is with a view to reducing the potential for any future significant price changes.

For the rate of return, NSW/ACT DNSPs were required to submit an indicative range that:⁹

- takes into account available market information
- takes into account expected market trends
- has regard to the rate of return guideline published by the AER.¹⁰

The indicative ranges for rate of return parameters proposed in the TRPs are higher than the ranges that we would have expected. If our foundation model set out in our guideline had been applied, this would have resulted in a range outside of and lower than the ranges proposed by each of the NSW/ACT DNSPs.

We have been guided by the methods and point estimates established in the guideline process in making this decision, given the limited scope of this placeholder determination. The rate of return guideline was published in December 2013. It was informed by extensive public consultation and based on robust engagement with consumers, NSW/ACT DNSPs and other interested stakeholders.¹¹ We consider the guideline encapsulates an outcome reached after careful consideration and deliberation with stakeholders across the market. Further, we consider that the approaches set out in our guideline take into account available market information and expected market trends. We therefore consider that to the extent that we have utilised the approaches and principles from the guideline in our foundation model analysis for assessing the rate of return, this meets the NER and the NEL requirements. Therefore, this is most likely to result in outcomes that are in the long-term interests of consumers. For the same reasons, we have adopted a value of γ that is consistent with our rate of return guideline. Given this analysis, we consider that the higher indicative rate of return ranges proposed by the NSW/ACT DNSPs result in higher or overstated annual revenue

⁸ The γ value impacts upon the cost of corporate income tax.

⁹ NER, cl 11.56.2(b)(2).

¹⁰ AER, *Rate of Return Guideline*, December 2013.

¹¹ The AER established the Consumer Reference Group (CRG) to facilitate consumer input into the 'Better regulation' project. The CRG provided a mechanism for coordinated and informed input from a cross-section of consumer groups. See also, AER, *Assessment of the Consumer Reference Group*, March 2014.

requirements, the recovery of which would not be consistent with the price variation test taking into account the NEO and RPPs. Accepting the proposed annual revenue requirements would mean that the NSW/ACT DNSPs' prices are likely to be higher in the transitional and subsequent regulatory control periods than is likely to be the case based on our rate of return analysis for the limited purpose of this determination. As such, each DNSP's proposed annual revenue requirement is not likely to contribute to the achievement of the NEO to the greatest degree and is not consistent with the RPPs in terms of promoting efficient investment.¹²

Accordingly, we are not satisfied that the proposed annual revenue requirements are reasonably likely to minimise price variations between the relevant periods and years because of the extent of this likely price difference as set out in our analysis. This has the potential to lead to a greater risk of more significant price changes for consumers contrary to the objective of the price variation test, which is intended to avoid such changes.

Apart from the rate of return and the value of gamma, we undertook a preliminary review of the other information that the NSW/ACT DNSPs were required to submit to us including their indicative estimates of forecast operating expenditure (opex) and capital expenditure (capex) for the transitional regulatory control period and their planned expenditures for the years 2015 to 2019. We are not required to conduct a building block assessment for this determination. We will assess opex and capex as proposed by the NSW/ACT DNSPs in their regulatory proposals (which are yet to be received) for the subsequent regulatory control period at the time of the full determination. In this determination, for the very limited purpose of determining a placeholder annual revenue requirement, we have used the proposed indicative estimates of opex, capex and the value of the opening regulatory asset base (RAB) as inputs in our price variation test analysis. We recognise that these inputs may not ultimately be reflected in the annual revenue requirement approved in the full determination. However, taking into account the RPPs, we consider that for the purpose of the placeholder annual revenue requirement, this approach will provide the NSW/ACT DNSPs with a reasonable opportunity to recover at least the efficient costs incurred in providing prescribed services in the transitional year under this placeholder determination given our adjustment to the rate of return and the value of gamma.¹³

Accept, or reject and substitute annual revenue requirement

We are not satisfied that the annual revenue requirements proposed in the respective TRPs of the NSW/ACT DNSPs are such that the recovery of those amounts is reasonably likely to minimise variations in prices between the relevant periods and years. We therefore do not accept the proposed annual revenue requirements in the TRPs of Ausgrid, Endeavour Energy, Essential Energy or ActewAGL. We approve instead amounts which we are satisfied are reasonably likely to minimise variations in prices.

In particular, we are rejecting and substituting the NSW/ACT DNSPs' proposed indicative annual revenue requirements with those based on revised inputs to the placeholder annual revenue requirements that have regard to our rate of return guideline and current available market information and trends. The rate of return guideline was published in December 2013 and was informed by extensive public consultation and rigorous analysis and debate. In arriving at our substitute annual revenue requirements, we have also adopted a value for gamma that is founded on our extensive analysis in that guideline.

¹² NER, cl 11.56.3(b); NEL, ss 7, 7A, 16(1)(a) and (d), and 16(2).

¹³ NEL, s 7A(2).

We consider these substitute annual revenue requirements are reasonably likely to minimise price variations between and within the relevant regulatory control periods and years.

Our conclusion, based on our high level analysis, takes into account insofar as is possible that the annual revenue requirement is made up of several constituent components. However, we are not tasked with conducting a building block analysis of these components for this determination. Further, decisions on other components have been prescribed or fixed under the transitional rules such that we are not required to exercise any discretion on those aspects. The approved annual revenue requirements, with the exception of the indicative ranges for the rate of return and the value of gamma, adopts all inputs into the annual revenue requirements proposed by the NSW/ACT DNSPs in the knowledge that these are unassessed estimates only and the annual revenue requirements will be subject to a true up. At the same time, our application of the price variation test takes into account the long-term interests of consumers by applying a rate of return that has regard to our guideline and takes into account expected market trends and available information, and a value of gamma that we are satisfied is a reasonable estimate based on the analysis undertaken for our guideline. Our approved annual revenue requirement recognises the interrelationship between these unassessed components and a rate of return based on our guideline to the extent possible, and a value for gamma that is also consistent with the guideline. It provides the NSW/ACT DNSPs with a reasonable opportunity to recover at least efficient costs and further, is likely to contribute to the NEO by promoting efficient investment in, and the efficient operation and use of, electricity services for the long-term interests of consumers particularly with respect to price.

Table 1.1 to Table 1.6 show the NSW/ACT DNSPs' proposed revenues (and price paths) for the transitional regulatory control period and our substituted revenues (and price paths) for the transitional regulatory control period.

Table 1.1 Ausgrid's proposed revenue and price path and AER substituted revenue and price path – distribution

	2013–14	2014–15	Change (%)	Difference from proposed 2014–15 (%)
Proposed revenue and price path				
Revenue (\$m, nominal)	2109	2076 ^a	-1.5%	n/a
Price path (nominal index)	1.00	1.00	0.3%	n/a
AER substitute revenue and price path				
Revenue (\$m, nominal)	2109	1958 ^a	-7.2%	-5.8%
Price path (nominal index)	1.00	0.95	-5.4%	-5.7%

Source: AER analysis.

Notes: a. Revenue figures include costs arising from ancillary network services and emergency recoverable works. Some of these costs are recovered through separate charges as discussed in section 4.1.

Table 1.2 Ausgrid's proposed revenue and price path and AER substituted revenue and price path – transmission

	2013–14	2014–15	Change (%)	Difference from proposed 2014–15 (%)
Proposed revenue and price path				
Revenue (\$m, nominal)	268	270	0.5%	n/a
Price path (nominal index)	1.00	1.00	0.2%	n/a
AER substitute revenue and price path				
Revenue (\$m, nominal)	268	252	–6.0%	–6.5%
Price path (nominal index)	1.00	0.94	–6.3%	–6.5%

Source: AER analysis.

Table 1.3 Essential Energy's proposed revenue and price path and AER substituted revenue and price path

	2013–14	2014–15	Change (%)	Difference from proposed 2014–15 (%)
Proposed revenue and price path				
Revenue (\$m, nominal)	1361	1363	0.1%	n/a
Price path (nominal index)	1.00	1.02	2.5%	n/a
AER substitute revenue and price path				
Revenue (\$m, nominal)	1361	1292	–5.1%	–5.2%
Price path (nominal index)	1.00	0.97	–2.8%	–5.2%

Source: AER analysis.

Table 1.4 Endeavour Energy's proposed revenue and price path and AER substituted revenue and price path

	2013–14	2014–15	Change (%)	Difference from proposed 2014–15 (%)
Proposed revenue and price path				
Revenue (\$m, nominal)	1015	1007 ^a	-0.8%	n/a
Price path (nominal index)	1.00	1.00	-0.2%	n/a
AER substitute revenue and price path				
Revenue (\$m, nominal)	1015	949 ^a	-6.5%	-5.8%
Price path (nominal index)	1.00	0.94	-6.0%	-5.7%

Source: AER analysis.

Notes: a. Revenue figures include costs arising from ancillary network services. Some of these costs are recovered through separate charges as discussed in section 4.1.

Table 1.5 ActewAGL's proposed revenue and price path and AER substituted revenue and price path – distribution

	2013–14	2014–15	Change (%)	Difference from proposed 2014–15 (%)
Proposed revenue and price path				
Revenue (\$m, nominal)	152 ^a	156	2.3%	n/a
Price path (nominal index)	1.00	1.05	4.8%	n/a
AER substitute revenue and price path				
Revenue (\$m, nominal)	152 ^a	145	-4.8%	-6.9%
Price path (nominal index)	1.00	0.98	-2.5%	-6.9%

Source: AER analysis.

Notes: a. This figure has been adjusted to reflect only the (notional) distribution component of 2013–14 revenue. The X factor to apply in adjusting distribution revenues from 2013–14 to 2014–15 is discussed in chapter 4.

Table 1.6 ActewAGL's proposed revenue and price path and AER substituted revenue and price path – transmission

	2013–14	2014–15	Change (%)	Difference from proposed 2014–15 (%)
Proposed revenue and price path				
Revenue (\$m, nominal)	28 ^a	30	7.8%	n/a
Price path (nominal index)	1.00	1.07	7.5%	n/a
AER substitute revenue and price path				
Revenue (\$m, nominal)	28 ^a	28	0.4%	-6.8%
Price path (nominal index)	1.00	1.00	0.1%	-6.8%

Source: AER analysis.

Notes: a. This figure has been adjusted to reflect only the (notional) transmission component of 2013–14 revenue.

2 About this review

This chapter provides an overview of the NSW/ACT DNSPs and an outline of our approach for making a placeholder determination for the transitional regulatory control period.

2.1 Overview of the NSW/ACT DNSPs

Ausgrid, Endeavour Energy and Essential Energy in NSW and ActewAGL in the ACT are the subject of this placeholder determination.

- Ausgrid operates the densest electricity distribution network in NSW providing services to over 1.6 million customers in Sydney, the Central Coast and the Hunter Region. Ausgrid's opening asset base for the current regulatory control period (in June 2012 dollars) is over \$9 billion. It is the largest RAB of all the distribution businesses in the NEM.
- Endeavour Energy's network spans 24,500 square kilometres covering Sydney's Greater West, the Illawarra and South Coast, the Blue Mountains, the Southern Highlands and Shoalhaven. Endeavour Energy services over 880,000 customers.
- Essential Energy operates one of the geographically largest distribution networks in Australia. Its network consists of 190,777 kilometres of distribution lines which cover three quarters of NSW and parts of southern Queensland. Essential Energy services approximately 800,000 customers.
- In July 2012, Ausgrid, Essential Energy and Endeavour Energy merged to form the state-owned entity, Networks NSW. The three businesses are run by the same CEO and senior management but remain functionally and legally separate. For this reason, Ausgrid, Essential Energy and Endeavour Energy submitted separate TRPs to the AER.
- ActewAGL is a joint public-private company. It is the only electricity DNSP in the ACT. It services over 170,000 customers.

2.2 Review process

The review process for this transitional year differs from our review process under a normal determination. In particular and as shown in Table 2.1, the timeframes are considerably condensed, with the review from start to finish being three months. We had a single consultation period, during which we sought submissions during a period of 20 business days. All submissions received are available on our website and are listed at Appendix A. We also consulted with:

- our NSW and ACT jurisdictional consumer groups
- our Consumer Challenge Panel (CCP) subpanel, formed for the NSW/ACT electricity distribution determinations
- the NSW/ACT DNSPs.

The NSW/ACT DNSPs submitted TRPs to the AER on 31 January 2014. In accordance with the transitional rules, the NSW/ACT DNSPs were not required to submit the kind of information that is required for a full five year determination. Information of that kind, such as details about particular expenditure projects and demand forecasts, must be submitted as part of their regulatory proposals for the full determination. A brief summary of the information contained in the TRPs can be found in Appendix B.

Consumer Challenge Panel

We have formed a CCP subpanel for the NSW/ACT electricity distribution determinations (the CCP subpanel). The CCP subpanel met with AER staff on several occasions during our consideration of the TRPs. It also met with all of the NSW/ACT DNSPs after they submitted their TRPs. It considered the TRPs in the context of the broader review of the NSW/ACT DNSPs subsequent regulatory proposals.

The subpanel provided advice to us on the TRPs. In their advice, the subpanel expressed the view that it has an expectation that distribution prices will decrease, preferably in nominal terms over the 2014–19 period. In discussions with the NSW/ACT DNSPs and AER staff, the CCP subpanel indicated they would like the NSW/ACT DNSPs to improve their consumer engagement.

Submissions

We received a total of ten submissions on the TRPs. All submissions received are available on our website and are listed at Appendix A. In making our determination we have had regard to these submissions. We received submissions on the following issues:

- Revenues
- Capex
- Opex (including EBSS)
- WACC
- Metering services (including smart meters)
- Demand management
- Tariff structures
- Control mechanism
- Service standards
- Pricing methodology

We have incorporated references to and discussion of these submissions in this decision document. We will be able to respond more appropriately to some of these submissions in our draft determinations for the subsequent regulatory control period.

Table 2.1 Key dates in the AER's transitional decision making process

Key stages in the decision making process	Date
Submission of NSW/ACT DNSPs' transitional regulatory proposals to the AER	31 January 2014
Publication of NSW/ACT DNSPs' transitional regulatory proposals	4 February 2014
Submissions on NSW/ACT DNSPs' transitional regulatory proposals due	3 March 2014
Publication of AER placeholder determination	By 30 April 2014

Source: AER analysis.

2.2.1 Protected information submitted to the AER

We are committed to treating protected information received from DNSPs and other stakeholders in accordance with the NEL. The NEL allows us to disclose protected information in certain circumstances.¹⁴ This decision contains no sensitive information.

2.2.2 Structure of this document

The remaining parts of this placeholder determination are set out as follows:

Section 3: AER's approach

Section 4: Indicative annual revenue requirement

Section 5: Other constituent decisions

¹⁴ NEL, Part 3, division 6.

3 AER's approach

This chapter outlines the legal requirements informing the AER's decisions and an explanation of the AER's assessment approach.

3.1 Assessment criteria

The AER must first assess whether the TRPs comply with the content requirements in the transitional rules.¹⁵ The AER must then assess the substantive content of the TRPs.

Several of the decisions that the AER must make are fixed in the transitional rules. For example, the length of the regulatory control period is a decision that is required to be made in the terms set out in the transitional rules. In these circumstances, the AER must make the decision that is required by the transitional rules without needing to take any further analysis.

Some constituent decisions are required to take the form set out in the transitional rules or in the relevant Framework and Approach paper. This includes decisions on the application of the efficiency benefit sharing scheme (EBSS). The AER must make a decision in its determination that reflects those requirements.

The AER is required, however, to exercise discretion when assessing the proposed annual revenue requirement nominated by the NSW/ACT DNSPs.

The criteria applied in this assessment is different to the standard building block approach that is normally applied by us in a full determination. A complete building block assessment will occur following receipt of the full regulatory proposals. By contrast, the assessment for the placeholder determination is a much more limited and confined assessment both in time and scope. In its final determination in 2012, the AEMC explained:

...[t]he AER [is] to apply relatively high level criteria when assessing a NSP's proposal, rather than undertaking a detailed assessment that would usually be required [under] the rules. Put another way, the AER is not required to justify its decision about the placeholder revenue by applying a building block model to estimate a NSP's placeholder revenue requirements.¹⁶

We may only approve the amount proposed if we are satisfied that:

"the amount is such that recovery of it by [NSP]...is reasonably likely to minimise variations in prices between the... current regulatory control period, transitional regulatory control period and subsequent regulatory control period and between the regulatory years of the subsequent regulatory control period."¹⁷

As to this requirement to minimise price variations, the AEMC noted it was desirable that the transitional rules not give rise to one-off price shocks:

"Prices should not be distorted when moving from the previous rules to the new rules, unless the underlying economic costs of the NSP's change. The transitional arrangements seek to minimise the potential for one-off price shocks for consumers in this regard and therefore provide appropriate price signals to consumers."¹⁸

¹⁵ NER, cl 11.55.2(b); 11.56.2(a).

¹⁶ AEMC Final Rule Determination, p. 237.

¹⁷ NER, cl 11.56.3(b). A "regulatory year" is "[e]ach consecutive period of 12 calendar months in a regulatory control period, the first such 12 month period commencing at the beginning of a regulatory control period and the final 12 month period ending at the end of the regulatory control period": Chapter 10 NER.

¹⁸ AEMC Final Rule Determination, p.15.

In deciding whether to approve the proposed revenue proposal, we also must take into account the revenue pricing principles (RPPs), and perform or exercise our functions or powers in a manner that will or is likely to contribute to the achievement of the national electricity objective.¹⁹

The transitional rules expressly require us to have regard to the fact that the annual revenue requirement for the transitional regulatory control period is an estimate that is based on indicative inputs. The determination for the subsequent regulatory control period will make an adjustment to the total revenue cap/requirement for the subsequent regulatory control period in accordance with the transitional rules.

We must also have regard to:

- the information included in or accompanying the proposal
- submissions received in the course of consulting on the proposal
- analysis undertaken by or for us in connection with the proposal.²⁰

If we do not approve the amount proposed for the transitional regulatory control period, then we must approve an amount that we are satisfied is such that the recovery of it by the affected DNSPs reasonably likely to minimise variations in prices between the affected DNSP's current regulatory control period, transitional regulatory control period and subsequent regulatory control period and between the regulatory years of the subsequent regulatory control period.²¹

As required by the transitional rules, our analysis is therefore directed at assessing the annual revenue requirement proposed by the DNSP against the above criteria aimed at minimising price variations.

More generally, we note that in assessing the proposal we must set out the basis and rationale for our decision. This must include details of any qualitative or quantitative methodologies applied by us, the values adopted by us in any calculations and formulae, details of any assumptions made by us and reasons for the making of any decisions, the giving or withholding of any approvals, and the exercise of any discretion.

3.2 Assessment approach

Under the price variation test, our decision to approve or not approve the proposed annual revenue requirement for the transitional period requires us to form a view about the expected movement of prices from 2013 to 2014, 2014 to 2015 and so on until 2019. This view necessarily reflects our expectations of future revenues and demand.

Our expectations of future revenues are based on our assessment of the information currently available to us which includes indicative estimates or ranges of key inputs included in the proposals. We have largely relied upon these proposed indicative inputs but have paid particular attention to the indicative rate of return and 'tax imputation credits' (gamma) proposed by the DNSPs in support of their proposals. In considering a reasonable indicative rate of return, we have had regard to the proposals, to our own guideline, to available market information and expected market trends, After making an adjustment to the rate of return and to the value of gamma used to support NSW/ACT

¹⁹ NEL, s 16; AEMC Final Rule Determination, p. 238.

²⁰ NER, cl 11.56.3(b).

²¹ NER, cl 11.58.3(d).

DNSPs' proposals, we then consider the TRPs in the context of the price variation test taking into account the NEO and RPPs.

We consider this approach should not, in any way, be taken as an indication of our assessment of the full regulatory proposals that the NSW/ACT DNSPs have yet to submit for the purposes of the full determination. In that full determination, a true-up of revenue for the transitional period will be conducted. The approach and conclusions in this determination are purely for the limited purposes of making the required assessment we must make for this transitional period under the transitional rules.

4 Revenues for the transitional year

This chapter contains indicative annual revenue requirements for the NSW/ACT DNSPs for 2014–15 and states whether we accepted, or rejected and substituted the DNSP’s revenue proposal. This is followed by an explanation on how the AER reached its decision, including the key drivers of the annual revenue requirement and adjustments necessary for revenues recovered through separate fees and charges.

4.1 Annual revenue requirement for transitional year

We make the following decisions in relation to the annual revenue requirement:

- We do not approve Ausgrid’s proposed annual revenue requirement of \$2076 million (\$ nominal) for distribution network services. Instead we have substituted a revenue allowance of \$1958 million (\$ nominal). We do not approve Ausgrid’s proposed annual revenue requirement of \$270 million (\$ nominal) for transmission services. Instead we have substituted a revenue allowance of \$252 million (\$ nominal).
- We do not approve Essential Energy’s proposed annual revenue requirement of \$1363 million (\$ nominal). Instead we have substituted a revenue allowance of \$1292 million (\$ nominal).
- We do not approve Endeavour Energy’s proposed annual revenue requirement of \$1007 million (\$ nominal). Instead we have substituted a revenue allowance of \$949 million (\$ nominal).
- We do not approve ActewAGL’s proposed annual revenue requirement of \$156 million (\$ nominal) for distribution network services. Instead we have substituted a revenue allowance of \$145 million (\$ nominal). We do not approve ActewAGL’s proposed annual revenue requirement of \$30 million (\$ nominal) for transmission services. Instead we have substituted a revenue allowance of \$28 million (\$ nominal).

This is because recovery of the indicative annual revenue requirements proposed by the NSW/ACT DNSPs is not reasonably likely to minimise price variations between the relevant periods and years as required under the transitional rules.²² We are satisfied that our substituted revenues for the NSW/ACT DNSPs are reasonably likely to minimise variations in price consistent with the requirements of the transitional rules.²³

Our decision on the NSW/ACT DNSPs’ distribution and transmission revenues—distribution use of system (DUOS) and transmission use of system (TUOS)—for the transitional regulatory control period is as set out at Table 4.1. For the transitional year, these revenues in some cases need to recover the costs of metering, ancillary network services (ANS) and emergency recoverable works (ERW). However, some of these costs can also be recovered through separate (non-DUOS) charges. Where this occurs, adjustments are made to recognise these other sources of revenue.

²² NER, cl 11.56.3(b).

²³ NER, cl 11.56.3(d).

Table 4.1 DUOS and TUOS for the transitional regulatory control period (\$m, nominal)

NSW/ACT DNSP	Network	Proposed revenue	AER approved revenue	Difference from proposed revenue
Ausgrid ^a	Distribution	2075	1956	-119 (-5.7%)
	Transmission	270	252	-18 (-6.5%)
Essential Energy	Distribution	1363	1292	-71 (-5.2%)
Endeavour Energy ^a	Distribution	998	940	-58 (-5.8%)
ActewAGL	Distribution	156	145	-11 (-6.9%)
	Transmission	30	28	-2 (-6.8%)

Source: AER analysis.

Notes: Numbers may not sum due to rounding.

- a. Revenues presented reflect 'DUOS-only' revenue. For Ausgrid (distribution) and Endeavour Energy, expected revenues from ancillary network services (ANS) and/or emergency recoverable works (ERW)—\$19 million and \$10 million respectively—have been removed for comparison across DNSPs and to clarify the revenues to be recovered through DUOS charges. ANS prices for the transitional regulatory control period are discussed in section 5.7.2.

Section 4.1.1 discusses our high level assessment of the proposed indicative revenues and the reasons behind our decision that are common to each DNSP. We then present the outcomes of our assessment that are specific to each DNSP. Throughout this section, where we discuss overall revenue, we do so with regard to the context that changes in revenue translate to changes in prices, which is the primary focal point of the price variation test.²⁴ However, determining a precise price path is not possible based on the data before the AER. Prices have various components such as fixed charges, capacity charges, time of use charges and volume charges. Under a revenue cap businesses do not typically provide this data with their regulatory proposals, whereas under a price cap they would. We therefore present indicative price indexes in this section.

Endeavour Energy and Essential Energy's TRPs included data for price cap calculations (in addition to their revenue cap calculations) in their PTRMs, which allowed us to use the overall price impact from these calculations to determine the movement in prices. Ausgrid provided data on price changes resulting from its proposed revenue for its distribution network, which appeared to be consistent with price cap calculations. As such, we were able to adopt the overall price impact from these calculations to determine the movement in prices. For ActewAGL's and Ausgrid's transmission networks, we determined prices by dividing total revenue by total energy consumed (KWh).²⁵ For presentational purposes (and regardless of how the prices were calculated), the prices were scaled so that the price index begins at 1.0 for each network in 2013–14.²⁶ These indexes provide a simple overall measure of the relative movement in prices across time.

²⁴ Changing the demand forecast would change the prices that result from a given total revenue figure, but we have adopted the DNSPs' demand forecasts for the purposes of this placeholder determination.

²⁵ For ActewAGL's distribution business the KWh used were those forecast by ActewAGL. However, for both ActewAGL's and Ausgrid's transmission networks we used KWh as forecast by TransGrid which were based on AEMO's forecast for NSW. This approach is further discussed in the AER's placeholder determination for TransGrid, see AER, *TransGrid Transend, Transitional transmission determinations 2014–14*, March 2014.

²⁶ The different techniques used to construct the index for each particular network are explained separately.

4.1.1 AER's reasons

We do not accept the NSW/ACT DNSPs' proposed annual revenue requirements for the transitional regulatory control period. Instead we have substituted revenues as set out below. This is because after considering the key revenue drivers as an input into the annual revenue requirements, our analysis indicates that the proposed annual revenue requirements are likely to be overstated.

In particular, based on the rate of return guideline, we expect forecast costs that are influenced by the rate of return on capital and the value of imputation credits (γ) to be lower than those proposed by the DNSPs. With regard to our rate of return guideline, and taking into account available market information and expected market trends, we expect the rate of return to be lower and the value of γ higher than proposed. This then leads to lower building blocks for the return on capital and cost of corporate income tax. Our reasoning on these issues is set out in sections 4.2.1 and 4.2.5, respectively.

We consider that annual revenue requirements that incorporate a rate of return and γ that more accurately have regard to these factors are reasonably likely to minimise price variations. Given this, our assessment at the time of this placeholder determination is that the annual revenue requirements proposed by the DNSPs are not reasonably likely to minimise variations in price. This is because the DNSPs' proposals are not likely to reduce the potential for future significant price changes for consumers. If we did not make the adjustments now to reflect the revenues established in this placeholder determination, but instead waited one year until the full determination, there would be a larger impact on prices. That is, if we were to wait one year before making the same adjustment to these inputs (all else being equal), the impact on revenues and prices would be larger and so therefore the impact on prices as well. It would be larger because the additional over-recovery of revenue in 2014–15 needs to be accounted for in the remaining four years of the subsequent regulatory control period.²⁷

With respect to price variations, we consider that if the reduction to the revenue is not made in this decision, then any resulting over-recovery in the transitional regulatory control period would be reasonably likely to lead to more significant price variations over the relevant regulatory control periods and years. This would therefore not be likely to contribute to the achievement of the NEO to the greatest degree and is not consistent with the RPPs in terms of promoting efficient investment.²⁸

We note submissions from the Public Interest Advocacy Centre and Major Energy Users stating their concerns with the DNSPs' smoothing approach to derive the placeholder determinations.²⁹ We agree that only the revenue for the transitional regulatory control period is being established. However, we must also consider the impact of price variations over the relevant regulatory control periods and years. To this end, we consider that the smoothing approach employed by the NSW/ACT DNSPs for the subsequent regulatory control period contributes to minimising price variations. For the purposes of this placeholder determination we have adopted their smoothing approach for the subsequent regulatory control period, but we have adjusted the revenue for the transitional regulatory control period.³⁰ We will have to review the smoothing approach for the subsequent regulatory control period

²⁷ It would also include a further increase reflecting the time value of money.

²⁸ NER, clause 11.56.3(b); NEL, s 7, 7A; s 16(1)(a), s 16 (2).

²⁹ Major Energy Users, NSW electricity distribution revenue reset: Ausgrid application for transition year 2014/15—A response, February 2010, p. 11; Major Energy Users, NSW electricity distribution revenue reset: Essential Energy application for transition year 2014/15—A response, February 2010, p. 11; Major Energy Users, NSW electricity distribution revenue reset: Essential Energy application for transition year 2014/15—A response, February 2010, p. 11.

³⁰ More specifically, in our analysis we retained the X-factors for years 2 to 5 (that is, the subsequent regulatory control period) proposed by the DNSPs for each network. However, see below for details on applying this principle to ActewAGL's transmission network.

as part of the full determination process, just as we will have to consider all other elements of the full proposal before making the full determination.

Determining DUOS and TUOS charges

As noted above, the DUOS revenues for the NSW DNSPs in Table 4.1 included costs associated with metering. These costs are allocated to standard control services in the transitional regulatory control period (as required by the NER) but will not be allocated to standard control services in the subsequent regulatory control period.

The DUOS revenues for the NSW DNSPs in Table 4.1 also include a certain proportion of costs associated with ANS and ERW.³¹ The NSW DNSPs stated that the costs of providing ANS and ERW are greater than what is recovered through separate ANS fees and ERW charges.³² Therefore, the shortfall from these services in 2014–15 will be recovered through DUOS charges in the transitional regulatory control period.³³ In the subsequent regulatory control period, cost reflective prices will be introduced for ANS. Each of the NSW DNSPs has accounted for the ANS and ERW costs in a different way. Endeavour Energy has included the full costs associated with ANS and/or ERW in the building block costs and then deducted from the annual revenue requirement the revenues expected to be recovered through the separate ANS fees and/or ERW charges. In doing so, only the net costs are recovered through DUOS. Essential Energy has instead netted off the revenues recovered through the separate ANS fees and ERW charges from the total costs of ANS and ERW before adding only the net costs to the building block costs. In this case, no further adjustment to the annual revenue requirement is necessary in determining the DUOS charges. Ausgrid has adopted a third approach with the capital costs included in the building block costs) and then netted off the revenues recovered through the separate ANS fees and ERW charges from the opex costs forecast for these services in 2014–15.³⁴ Regardless of the approach adopted, only the net costs of ANS and ERW are included in the DUOS charges for each of the NSW DNSPs. These adjustments (where relevant) are shown in the network specific tables below.

The transmission revenues set out in Table 4.1 for Ausgrid and ActewAGL relate to dual function assets. Dual function assets are parts of a DNSP's network that operate in support of the higher voltage transmission network.³⁵ For dual function assets operated by Ausgrid and ActewAGL, we apply transmission pricing rules instead of distribution pricing rules.³⁶ We refer to a DNSP's dual function assets as 'transmission assets' and related costs and revenues as 'transmission' costs and revenues.

Ausgrid

We do not accept Ausgrid's proposed annual revenue requirements for the transitional regulatory control period. Instead, we have substituted annual revenue requirements of \$1938 million and

³¹ ANS include items that were previously referred to as monopoly services, miscellaneous services and/ or ancillary services. They are services for which separate fees are charged.

³² That is, the ANS fees are below cost, and not all emergency works can be allocated to a responsible party for charging.

³³ ActewAGL has cost reflective tariffs for ANS. These costs are recovered separately and therefore they do not enter the building block costs and DUOS charges.

³⁴ Ausgrid advised that it did not have time to separately identify the relevant assets in the RAB used for ANS. Ausgrid, *Email: Confirmation of high level numbers*, 4 April 2014.

³⁵ NER, cl. 6.24.2(a).

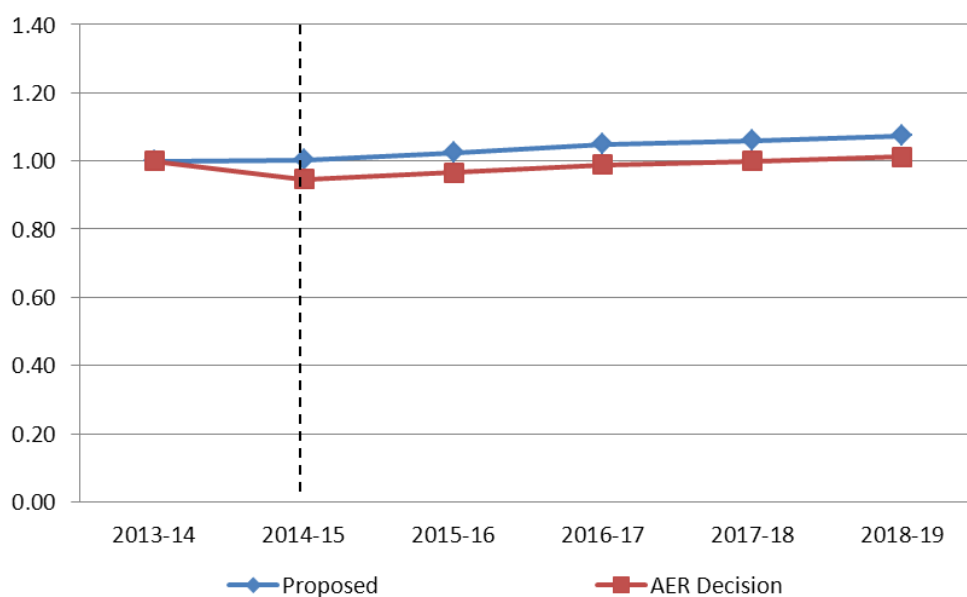
³⁶ For Ausgrid, under the transitional rules, our determination to apply transmission pricing in the current period means transmission pricing will also apply in the transitional period. For ActewAGL, to apply transmission pricing to its dual function assets, which are new, we were required to make a determination. We set this out in our *Stage 2 framework and approach for ActewAGL*, published in January 2014.

\$252 million (nominal), respectively.³⁷ This is 5.8 per cent and 6.5 per cent lower than the respective revenue allowances proposed by Ausgrid.³⁸ We consider that these substituted revenues are likely to minimise price variations and better reflect the efficient costs of the networks.

We note that Ausgrid has forecast under-recovery of 2013–14 revenues for its transmission network of \$20 million (nominal).³⁹ Under a revenue cap, Ausgrid can recover this amount in later years.⁴⁰ Any decision by Ausgrid to recover this revenue in the transitional regulatory control period would affect transmission prices for its customers independently of our placeholder determination. The indicative prices submitted by Ausgrid suggest that it will seek to recover this amount in the transitional regulatory control period.

Figure 4.1 and Figure 4.2 respectively show Ausgrid’s indicative price paths based on its proposed revenues for its distribution and transmission networks, and the price paths based on our revenues adjusted for the rate of return and gamma.⁴¹ For the reasons discussed above, we consider our adjusted revenues for Ausgrid’s distribution and transmission networks over the transitional regulatory control period are reasonably likely to result in price paths that minimise price variations. This is because we expect forecast costs to be lower than that proposed by Ausgrid.

Figure 4.1 Ausgrid proposed and AER decision indicative price path – distribution (nominal price index)



Source: AER analysis.

³⁷ The amount of \$1938 million (\$ nominal) represents total DUOS revenue. Adjustments of \$19 million have been made to account for expected ANS and ERW revenues recovered through separate charges.

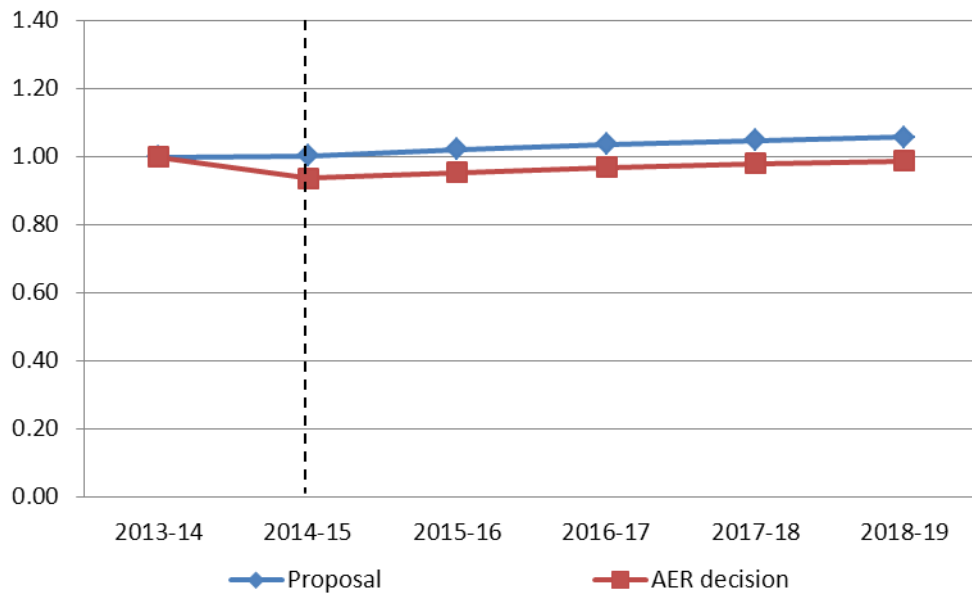
³⁸ For the distribution network, this calculation is relative to Ausgrid’s proposed annual revenue requirement after adjustment for the \$19 million attributable to ANS and ERW charges (i.e. \$2057 million).

³⁹ Ausgrid, *Transitional regulatory proposal*, January 2014, p. 26.

⁴⁰ Ausgrid’s distribution network does not operate under a revenue cap, so the issue does not arise there.

⁴¹ The price paths show the indicative weighted average change in distribution or transmission prices across Ausgrid’s network, scaled so that the price index begins at 1.0 in 2013–14. For Ausgrid’s distribution network, the nominal price index is calculated by the AER based on the indicative weighted average price changes submitted by Ausgrid in its TRP, and (where relevant) adjusting for the change in overall revenue substituted by the AER. See Ausgrid, *Transitional regulatory proposal*, January 2014, p. 24 (table 16). For Ausgrid’s transmission network, the nominal price index is

Figure 4.2 Ausgrid proposed and AER decision indicative price path – transmission (nominal price index)



Source: AER analysis

Notes: Calculated by the AER based on overall revenue and the (state wide) transmission network energy forecasts proposed by TransGrid (the NSW/ACT TNSP).

Table 4.2 and Table 4.3 respectively show Ausgrid’s distribution and transmission networks proposed revenues (and price paths) for the transitional and subsequent regulatory control periods and our substituted revenues (and price paths) for the transitional and subsequent regulatory control periods.

Table 4.2 Ausgrid’s proposed revenue and price path and AER substituted revenue and price path – distribution

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Proposed revenue and price path						
Revenue (\$m, nominal) ^a	2109	2075	2122	2168	2206	2253
Price path (nominal index)	1.00	1.00	1.02	1.05	1.06	1.07
Revenue (change %)	n/a	-1.6%	2.3%	2.2%	1.7%	2.1%
Price path (change %)	n/a	0.3%	2.1%	2.4%	1.0%	1.2%
AER substitute revenue and price path						
Revenue (\$m, nominal) ^a	2109	1956	2001	2045	2080	2124
Price path (nominal index)	1.00	0.95	0.97	0.99	1.00	1.01
Revenue (change %)	n/a	-7.2%	2.3%	2.2%	1.7%	2.1%
Price path (change %)	n/a	-5.4%	2.1%	2.4%	1.0%	1.2%

Source: AER analysis.

Notes: Numbers may not sum due to rounding.

- a. Ausgrid’s proposed revenues and price path include metering costs in all years—notwithstanding that costs for these services will be allocated differently in the subsequent regulatory control period. For comparability, the AER revenue and price path are prepared on the same basis. In this table, expected net revenues from ANS in 2014–15 of \$1 million have been removed to preserve comparability with the Ausgrid proposal.

Table 4.3 Ausgrid’s proposed revenue and price path and AER substituted revenue and price path – transmission

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Proposed revenue and price path						
Revenue (\$m, nominal)	268	270	275	281	286	292
Price path (nominal index)	1.00	1.00	1.02	1.04	1.05	1.06
Revenue (change %)	n/a	0.5%	2.0%	2.0%	2.0%	2.0%
Price path (change %)	n/a	0.2%	1.9%	1.5%	1.2%	0.9%
AER substitute revenue and price path						
Revenue (\$m, nominal)	268	252	257	262	268	273
Price path (nominal index)	1.00	0.94	0.95	0.97	0.98	0.99
Revenue (change %)	n/a	-6.0%	2.0%	2.0%	2.0%	2.0%
Price path (change %)	n/a	-6.3%	1.9%	1.5%	1.2%	0.9%

Source: AER analysis.

Notes: Numbers may not sum due to rounding.

- Ausgrid has an under-recovery of \$19.8 million in its allowed revenue for 2013–14. Ausgrid’s TRP indicated this amount is to be recovered in the transitional regulatory control period and would flow through to transmission prices for customers independently of our placeholder determination. The AER’s substitute revenue in this table does not include recovery of any of this amount in 2014–15.

Table 4.4 and Table 4.5 respectively show our indicative revenue allowances for Ausgrid's distribution and transmission networks over the transitional and subsequent regulatory control periods. They show the break down by the key building block components. For distribution, it also shows the metering costs and revenues to be recovered separately from DUOS charges through ANS fees and ERW charges. To determine DUOS charges, the ANS and ERW revenues need to be deducted to prevent double recovery.

Table 4.4 AER's revenue assessment for Ausgrid – distribution (\$m, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Return on capital		990	1047	1108	1162	1215
Return of capital		118	141	163	149	162
Operating expenditure		551	551	591	570	577
Efficiency carryover		95	116	83	138	-
Net tax allowance		54	59	68	67	69
Metering costs		70	75	80	77	79
Total revenue (unsmoothed)		1879	1989	2094	2162	2102
Total revenue (smoothed)	2109	1958	2001	2045	2080	2124
less: adjustment for net revenues recovered from ANS and ERW outside DUOS ^a		1	-	-	-	-
less: smoothed metering costs transferred to ACS from 2015–16 ^b		-	75	81	77	79
Total DUOS revenue	2109	1956	1926	1964	2003	2046
Change ^c (%)		-7.2%	-1.6%	2.0%	2.0%	2.1%

Source: AER analysis.

Notes: Numbers may not sum due to rounding.

We have adopted the forecast capital and operating expenditure estimates of Ausgrid. These will be subject to detailed scrutiny when we receive the regulatory proposal.

- These net revenues are the amounts expected to be recovered through separate ANS fees and ERW charges less the opex costs associated with ANS and the ERW costs.
- This row shows the smoothed metering costs, so will not be exactly equal to the unsmoothed metering costs on the earlier row.
- This row shows the year-on-year change in total nominal revenues. It should not be interpreted as the X-factor change from year to year.

Table 4.5 AER's revenue assessment for Ausgrid – transmission (\$m, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Return on capital		170	181	193	199	206
Return of capital		12	16	20	17	19
Operating expenditure		42	42	45	43	44
Efficiency carryover		7	9	6	10	0
Net tax allowance		6	7	8	7	8
Total revenue (unsmoothed)		238	255	271	277	276
Total TUOS revenue (smoothed)	268	252	257	262	268	273
Change ^a (%)		-6.0%	2.0%	2.0%	2.0%	2.0%

Source: AER analysis.

Notes: Numbers may not sum due to rounding.

We have adopted the forecast capital and operating expenditure estimates of Ausgrid. These will be subject to detailed scrutiny when we receive the regulatory proposal.

As noted above, the AER's substitute revenue in this table does not include the under-recovery of \$19.8 million associated with Ausgrid's allowed revenue for 2013–14. Any decision by Ausgrid to recover this revenue would affect transmission prices for its customers independently of our placeholder determination.

a. This row shows the year-on-year change in total nominal revenues. It should not be interpreted as the X-factor change from year to year.

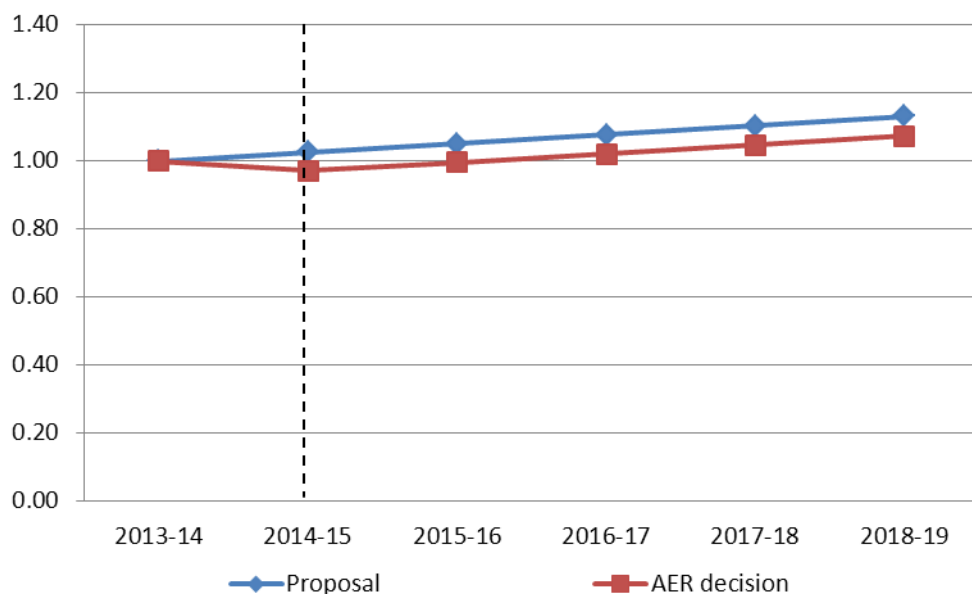
Essential Energy

We do not accept Essential Energy's proposed annual revenue requirement for the transitional regulatory control period. Instead, we have substituted an annual revenue requirement of \$1292 million (nominal). This is 5.2 per cent lower than the revenue allowance proposed by Essential Energy. We consider that this substituted revenue is likely to minimise price variations.

Figure 4.3 shows Essential Energy's indicative price path based on its proposed revenues and the price path based on our revenues adjusted for the rate of return and gamma.⁴² For the reasons discussed above, we consider our adjusted revenue for Essential Energy over the transitional regulatory control period is reasonably likely to result in a price path that minimises price variations. This is because we expect forecast costs to be lower than that proposed by Essential Energy.

⁴² The price paths show the indicative weighted average change in distribution prices across Essential Energy's network, scaled so that the price index begins at 1.0 in 2013–14. The nominal price index is calculated by the AER based on the indicative weighted average price changes and the demand forecasts submitted by Essential Energy in its TRP, and (where relevant) adjusting for the change in overall revenue substituted by the AER.

Figure 4.3 Essential Energy proposed and AER decision indicative price path (nominal price index)



Source: AER analysis.

Table 4.6 shows Essential Energy’s proposed revenue (and price path) for the transitional and subsequent regulatory control periods and our substituted revenue (and price path) for the transitional and subsequent regulatory control periods.

Table 4.6 Essential Energy’s proposed revenue and price path and AER substituted revenue and price path

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Proposed revenue and price path						
Revenue (\$m, nominal)	1361	1363	1375	1382	1390	1407
Price path (nominal index)	1.00	1.02	1.05	1.08	1.10	1.13
Revenue (change %)	n/a	0.1%	0.9%	0.5%	0.6%	1.2%
Price path (change %)	n/a	2.5%	2.5%	2.5%	2.5%	2.5%
AER substitute revenue and price path						
Revenue (\$m, nominal)	1361	1292	1303	1310	1317	1334
Price path (nominal index)	1.00	0.97	1.00	1.02	1.05	1.07
Revenue (change %)	n/a	-5.1%	0.9%	0.5%	0.6%	1.2%
Price path (change %)	n/a	-2.8%	2.5%	2.5%	2.5%	2.5%

Source: AER analysis.

Notes: Numbers may not sum due to rounding.

Table 4.7 shows our indicative revenue allowance for Essential Energy over the transitional and subsequent regulatory control periods. It shows the break down by the key building block components

and the metering costs. No adjustment is made for revenues to be recovered separately from DUOS charges through ANS fees and ERW charges, because only the net costs of these items have been included by Essential Energy.

Table 4.7 AER's revenue assessment for Essential Energy (\$m, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Return on capital		547	586	620	654	687
Return of capital		99	118	132	135	129
Operating expenditure		481	479	475	484	497
Efficiency carryover		-15	-53	-48	39	-
Net tax allowance		38	40	42	46	45
Metering costs		58	59	62	69	78
Net ANS costs		12	-	-	-	-
Net ERW costs		1	-	-	-	-
Total revenue (unsmoothed)		1220	1230	1283	1427	1436
Total revenue (smoothed)	1361	1292	1303	1310	1317	1334
less: adjustment for revenues recovered from ANS and ERW outside DUOS		-	-	-	-	-
less: metering costs transferred to ACS from 2015–16.		-	59	62	69	78
Total DUOS revenue	1361	1292	1244	1247	1249	1256
Change ^a (%)		-5.1%	-3.7%	0.3%	0.1%	0.6%

Source: AER analysis.

Notes: Numbers may not sum due to rounding.

We have adopted the forecast capital and operating expenditure estimates of Essential Energy. These will be subject to detailed scrutiny when we receive the regulatory proposal.

a. This row shows the year-on-year change in total nominal revenues. It should not be interpreted as the X-factor change from year to year.

Endeavour Energy

We do not accept Endeavour Energy's proposed annual revenue requirement for the transitional regulatory control period. Instead, we have substituted an annual revenue requirement of \$940 million (nominal).⁴³ This is 5.8 per cent lower than the revenue allowance proposed by Endeavour Energy.⁴⁴ We consider that this substituted revenue is likely to minimise price variations.

Figure 4.4 shows Endeavour Energy's indicative price path based on its proposed revenues and the price path based on our revenues adjusted for the rate of return and gamma.⁴⁵ For the reasons

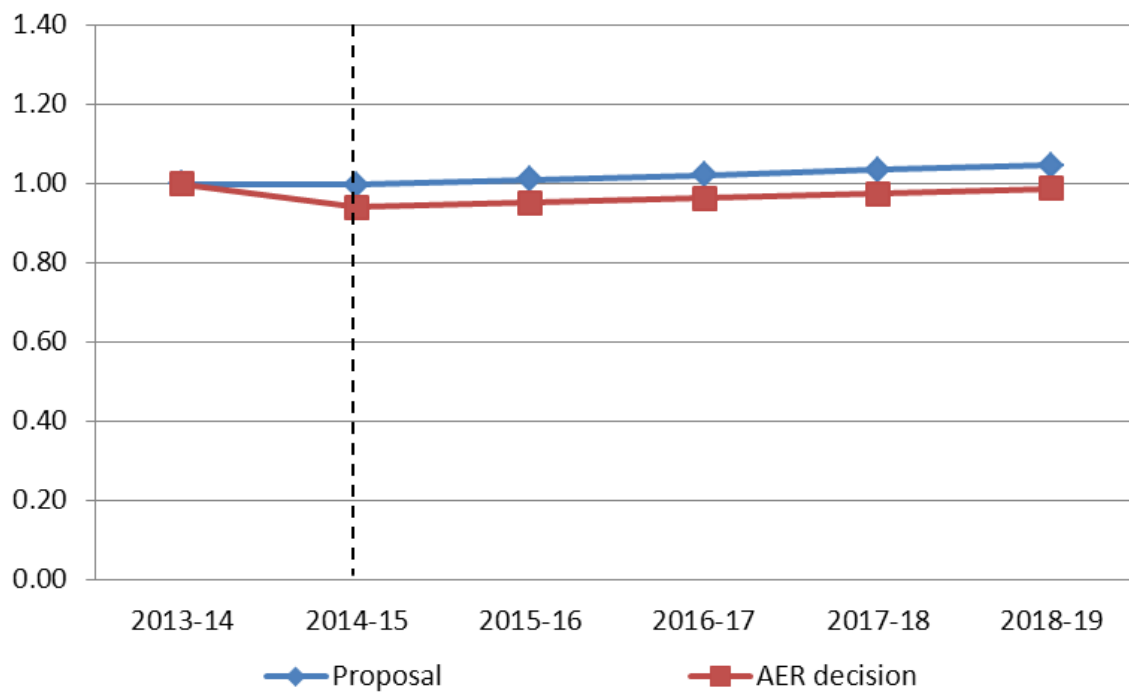
⁴³ The amount of \$940 million represents total DUOS revenue. Adjustments of \$10 million have been made to account for expected ANS and ERW revenues recovered through separate charges.

⁴⁴ This calculation is relative to Endeavour Energy's proposed annual revenue requirement, after adjusting for the ANS and ERW attributable charges (that is, \$998 million).

⁴⁵ The price paths show the indicative weighted average change in distribution prices across Endeavour Energy's network, scaled so that the price index begins at 1.0 in 2013–14. The nominal price index is calculated by the AER based on the

discussed above, we consider our adjusted revenue for Endeavour Energy over the transitional regulatory control period is reasonably likely to result in a price path that minimises price variations. This is because we expect forecast costs to be lower than that proposed by Endeavour Energy.

Figure 4.4 Endeavour Energy proposed and AER decision indicative price path (nominal price index)



Source: AER analysis.

Table 4.8 shows Endeavour Energy’s proposed revenue (and price path) for the transitional and subsequent regulatory control periods and our substituted revenue (and price path) for the transitional and subsequent regulatory control periods.

indicative weighted average price changes and the demand forecasts submitted by Endeavour Energy in its TRP, and (where relevant) adjusting for the change in overall revenue substituted by the AER.

Table 4.8 Endeavour Energy’s proposed revenue and price path and AER substituted revenue and price path

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Proposed revenue and price path						
Revenue (\$m, nominal) ^a	1015	1007	1007	1031	1053	1085
Price path (nominal index)	1.00	1.00	1.01	1.02	1.03	1.05
Revenue (change %)	n/a	-0.8%	0.0%	2.4%	2.1%	3.1%
Price path (change %)	n/a	-0.2%	1.2%	1.2%	1.2%	1.2%
AER substitute revenue and price path						
Revenue (\$m, nominal) ^a	1015	949	949	972	992	1023
Price path (nominal index)	1.00	0.94	0.95	0.96	0.98	0.99
Revenue (change %)	n/a	-6.5%	0.0%	2.4%	2.1%	3.1%
Price path (change %)	n/a	-6.0%	1.2%	1.2%	1.2%	1.2%

Source: AER analysis.

Notes: Numbers may not sum due to rounding.

- a. In this table, expected revenues from ANS in 2014–15 of \$10 million have not been removed to preserve comparability with the Endeavour Energy proposal.

Table 4.9 shows our indicative revenue allowance for Endeavour Energy over the transitional and subsequent regulatory control periods. It shows the break down by the key building block components and the total costs for metering and ANS. An adjustment is also made for revenues to be recovered separately from DUOS charges through ANS fees, so as to prevent double recovery of a proportion of ANS costs. Endeavour Energy did not forecast any ERW costs for the transitional regulatory control period. Endeavour Energy did not include any metering costs beyond 2014–15 in its transitional proposal. Therefore, no adjustment is necessary for determining DUOS charges from 2015–16 for the transfer of these services to ACS.

Table 4.9 AER's revenue assessment for Endeavour Energy (\$m, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Return on capital		451	482	507	527	549
Return of capital		63	72	83	88	93
Operating expenditure		292	300	303	305	316
Efficiency carryover		97	33	42	34	-
Net tax allowance		32	33	37	37	38
Metering costs		34	-	-	-	-
Total ANS costs		28	-	-	-	-
Total revenue (unsmoothed)		997	921	971	991	996
Total revenue (smoothed)	1015	949	949	972	992	1023
less: adjustment for revenues recovered from ANS outside DUOS		10	-	-	-	-
less: metering costs transferred to ACS from 2015–16.		-	-	-	-	-
Total DUOS revenue	1015	940	949	972	992	1023
Change ^a (%)		-7.4%	1.0%	2.4%	2.1%	3.1%

Source: AER analysis.

Notes: Numbers may not sum due to rounding.

We have adopted the forecast capital and operating expenditure estimates of Endeavour Energy. These will be subject to detailed scrutiny when we receive the regulatory proposal.

a. This row shows the year-on-year change in total nominal revenues. It should not be interpreted as the X-factor change from year to year.

ActewAGL

We do not accept ActewAGL's proposed annual revenue requirements for its distribution and transmission networks for the transitional regulatory control period. Instead, we have substituted annual revenue requirements of \$145 million and \$28 million (nominal), respectively. This is 6.9 per cent and 6.8 per cent lower than the respective revenue allowances proposed by ActewAGL. We consider that these substituted revenues are likely to minimise price variations and better reflect the efficient costs of the networks.

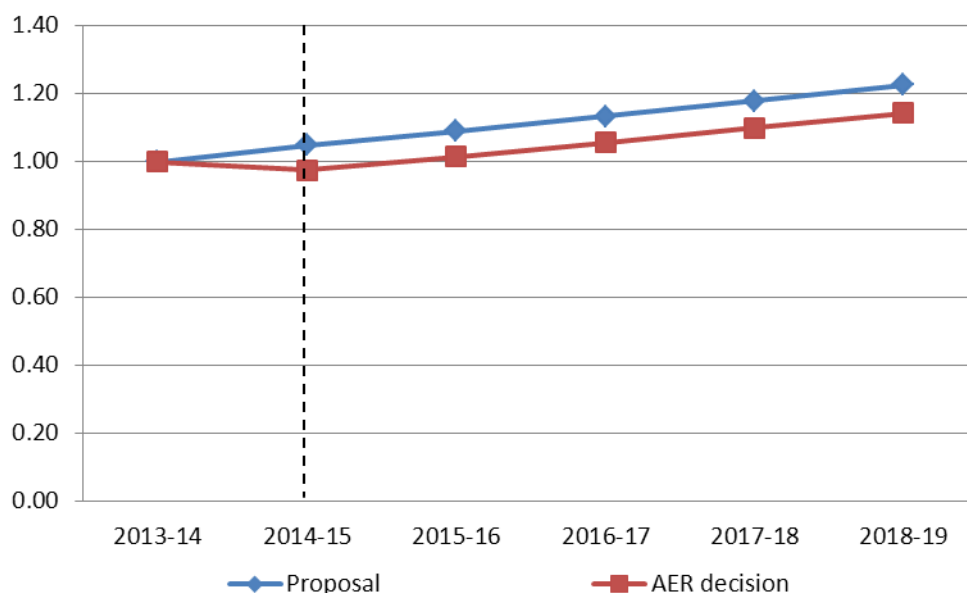
Figure 4.5 and Figure 4.6 respectively show ActewAGL's indicative price paths based on its proposed revenues for its distribution and transmission networks, and the price paths based on our revenues adjusted for the rate of return and gamma.⁴⁶ For the reasons discussed above, we consider our

⁴⁶ The price paths show the indicative weighted average change in distribution or transmission prices across ActewAGL's network, scaled so that the price index begins at 1.0 in 2013–14. For ActewAGL's distribution network, the nominal price index is calculated by the AER based on the revenue yield calculations submitted by ActewAGL in its distribution PTRM, and (where relevant) adjusting for the change in overall revenue substituted by the AER. For ActewAGL's transmission network, the nominal price index is calculated by the AER based on overall revenue and the (state wide) transmission network energy forecasts proposed by TransGrid (the NSW/ACT transmission network service provider).

When calculating our price path (and revenue), we retained the X-factors for years 2 to 5 (that is, the subsequent regulatory control period) proposed by ActewAGL. This was straight forward for ActewAGL's distribution network. However, for its transmission network, ActewAGL derived the X-factors for these years by setting them to equal the P_0 change from the transitional regulatory control period. We retained the X-factor values proposed by ActewAGL (-5.22 per cent for each year), rather than adjusting these when we recalculated the P_0 change.

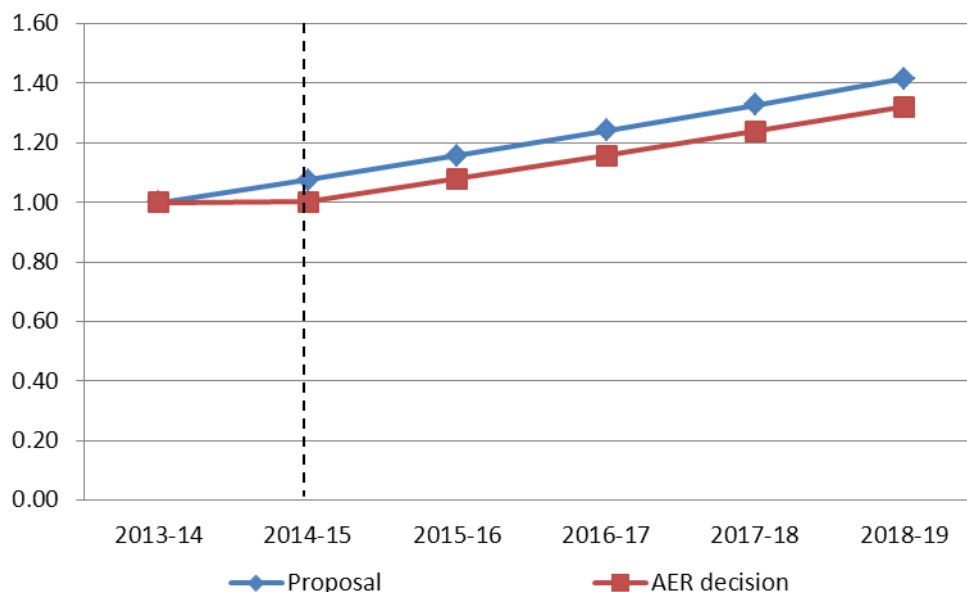
adjusted revenues for ActewAGL's distribution and transmission networks over the transitional regulatory control period are reasonably likely to result in price paths that minimise price variations. This is because we expect forecast costs to be lower than that proposed by ActewAGL.

Figure 4.5 ActewAGL proposed and AER decision indicative price path – distribution (nominal price index)



Source: AER analysis.

Figure 4.6 ActewAGL proposed and AER decision indicative price path – transmission (nominal price index)



Source: AER analysis.

Table 4.10 and Table 4.11 respectively show ActewAGL's distribution and transmission networks proposed revenues (and price paths) for the transitional and subsequent regulatory control periods

and our substituted revenues (and price paths) for the transitional and subsequent regulatory control periods.

Table 4.10 ActewAGL's proposed revenue and price path and AER substituted revenue and price path – distribution

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Proposed revenue and price path						
Revenue (\$m, nominal)	152 ^a	156	162	170	179	187
Price path (nominal index)	1.00	1.05	1.09	1.13	1.18	1.23
Revenue (change %)	n/a	2.3%	3.7%	5.2%	5.1%	4.5%
Price path (change %)	n/a	4.8%	4.0%	4.0%	4.0%	4.0%
AER substitute revenue and price path						
Revenue (\$m, nominal)	152 ^a	145	151	159	167	174
Price path (nominal index)	1.00	0.98	1.01	1.06	1.10	1.14
Revenue (change %)	n/a	-4.8%	3.8%	5.2%	5.2%	4.5%
Price path (change %)	n/a	-2.5%	4.0%	4.0%	4.0%	4.0%

Source: AER analysis.

Notes: Numbers may not sum due to rounding.

a. This figure has been adjusted to reflect only the (notional) distribution component of 2013–14 revenue.

Table 4.11 ActewAGL's proposed revenue and price path and AER substituted revenue and price path – transmission

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Proposed revenue and price path						
Revenue (\$m, nominal)	28 ^a	30	33	35	38	41
Price path (nominal index)	1.00	1.07	1.16	1.24	1.33	1.41
Revenue (change %)	n/a	7.8%	7.8%	7.8%	7.8%	7.8%
Price path (change %)	n/a	7.5%	7.7%	7.2%	6.9%	6.6%
AER substitute revenue and price path						
Revenue (\$m, nominal)	28 ^a	28	30	33	35	38
Price path (nominal index)	1.00	1.00	1.08	1.16	1.24	1.32
Revenue (change %)	n/a	0.4%	7.8%	7.8%	7.8%	7.8%
Price path (change %)	n/a	0.1%	7.7%	7.3%	7.0%	6.7%

Source: AER analysis.

Notes: Numbers may not sum due to rounding.

a. This figure has been adjusted to reflect only the (notional) transmission component of 2013–14 revenue.

Table 4.12 and Table 4.13 show our indicative revenue allowances for ActewAGL's distribution and transmission networks over the transitional and subsequent regulatory control periods. They show the

break down by key building block components. For ActewAGL's distribution network no adjustment is required for metering, ANS or ERW, with all costs recovered separately from the DUOS charges.

Table 4.12 AER's revenue assessment for ActewAGL – distribution (\$m, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Return on capital		56	60	63	65	68
Return of capital		27	31	31	33	33
Operating expenditure		65	65	63	64	69
Efficiency carryover		-13	-10	-2	-2	0
Net tax allowance		5	6	5	6	7
Total revenue (unsmoothed)		141	152	160	166	176
Total DUOS revenue (smoothed)	152^a	145	151	159	167	174
Change ^b (%)		-4.8%	3.8%	5.2%	5.2%	4.5%

Source: AER analysis.

Notes: Numbers may not sum due to rounding.

We have adopted the forecast capital and operating expenditure estimates of ActewAGL. These will be subject to detailed scrutiny when we receive the regulatory proposal.

a. This figure has been adjusted to reflect only the (notional) distribution component of 2013–14 revenue.

b. This row shows the year-on-year change in total nominal revenues. It should not be interpreted as the X-factor change from year to year.

Under the revenue yield approach applying to ActewAGL's distribution network, ActewAGL will need to apply an X factor of 19.59 per cent for 2014–15 in its control mechanism equation. This real decrease in average distribution charges reflects the transfer of previously classified distribution charges to transmission charges (14.75 per cent) and other distribution cost reductions (4.84 per cent).

Table 4.13 AER's revenue assessment for ActewAGL – transmission (\$m, nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Return on capital		12	13	14	16	17
Return of capital		4	5	5	6	6
Operating expenditure		13	13	13	13	14
Efficiency carryover		-2	-1	0	0	0
Net tax allowance		1	1	1	1	1
Total revenue (unsmoothed)		28	30	32	35	38
Total TUOS revenue (smoothed)	28^a	28	30	33	35	38
Change ^b (%)		0.4%	7.8%	7.8%	7.8%	7.8%

Source: AER analysis.

Notes: Numbers may not sum due to rounding.

We have adopted the forecast capital and operating expenditure estimates of ActewAGL. These will be subject to detailed scrutiny when we receive the regulatory proposal.

a. This figure has been adjusted to reflect only the (notional) transmission component of 2013–14 revenue.

b. This row shows the year-on-year change in total nominal revenues. It should not be interpreted as the X-factor change from year to year.

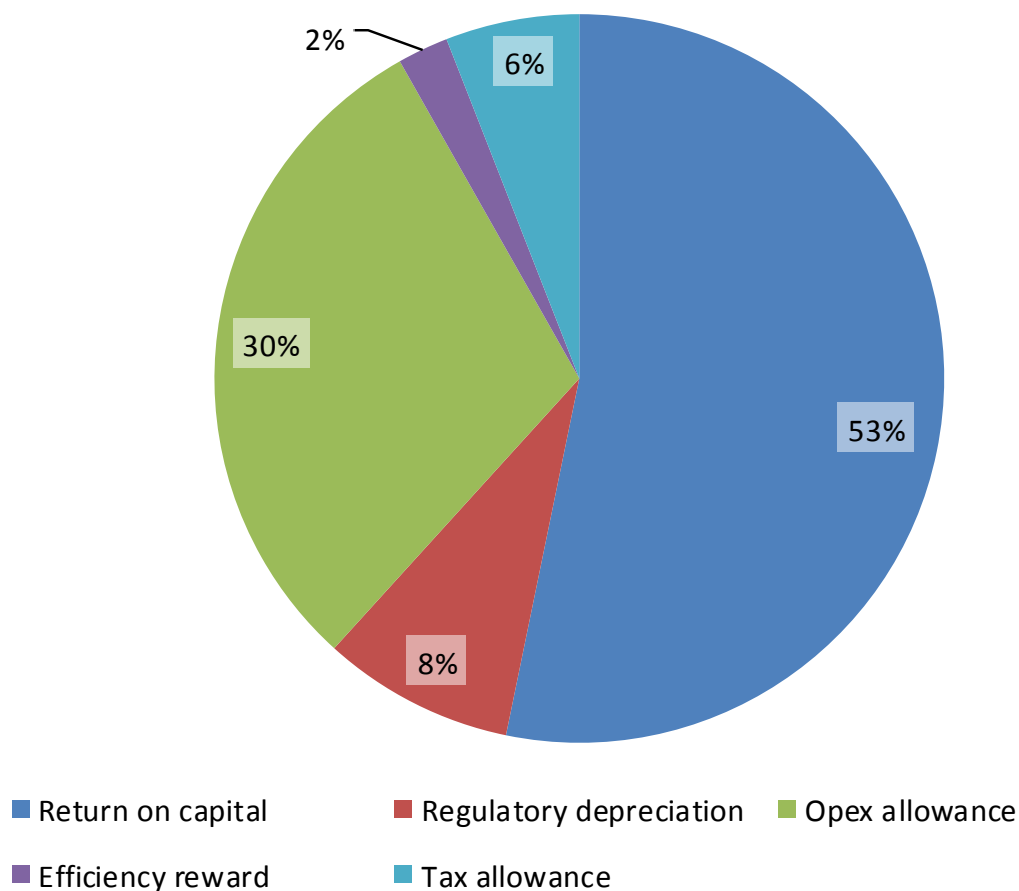
4.2 Key components and drivers of the annual revenue requirement

The annual revenue requirement for a regulatory control period is built up from various revenue components. These components include return on capital, regulatory depreciation, operating expenditure (opex), cost of corporate income tax and rewards/penalties of certain schemes (such as the efficiency benefit sharing scheme (EBSS) for opex). In most cases, these revenue components depend on other inputs or drivers. In particular:

- The return on capital depends on the size of the regulatory asset base (RAB) and the rate of return or weighted average cost of capital (WACC). The RAB in turn depends on the forecast capex allowance approved going forward and the amount actually spent in the past. The RAB is also indexed for inflation. The WACC also in turn depends on various drivers such as the return on debt and return on equity, and specific parameters such as the risk free rate.
- Regulatory depreciation (or return of capital) depends on the RAB (and in turn capex) and the useful lives of the assets, which determine over how many years the capex will be recovered. Because the RAB and WACC both include components for inflation, regulatory depreciation includes an offsetting inflation adjustment. This is to avoid the double counting of inflation when calculating total revenues.
- Opex depends on the various sources of operating expenses, including the size of the RAB.
- The cost of corporate income tax depends on the tax rate and all the inputs that determine the level of total revenue (including any rewards/penalties from schemes). It also depends, in particular, on the size of offsetting tax expenses (including tax depreciation) and the expected use of imputation credits by investors (gamma).
- Scheme rewards/penalties depend on the particulars of the scheme, including the actual performance of the DNSP measured under the scheme.

Figure 4.7 shows the relative size of these five revenue components for the NSW/ACT DNSPs based on their transitional regulatory proposals for the transitional and subsequent regulatory control periods. The return on capital (and its drivers such as RAB, capex and rate of return) makes up the largest proportion of total revenue at over 50 per cent. Opex makes up the next largest proportion at 30 per cent and regulatory depreciation (and its drivers such as RAB, capex and useful asset lives) makes up just under 10 per cent of total revenue. The remaining components of tax and scheme rewards/penalties make up less than 10 per cent of total revenue.

Figure 4.7 The relative size of the revenue components, total NSW/ACT



Source: AER analysis, using proposed revenue figures for 2014–19 for all DNSPs (including their distribution and transmission networks).

The following sections set out our views of these key components based on a high level assessment of the limited information available to us at this time, including the transitional regulatory proposals of the NSW/ACT DNSPs.

4.2.1 Rate of return

Ausgrid, Essential Energy and Endeavour Energy all proposed an indicative rate of return range from 8.5 to 9.1 per cent.⁴⁷ In this section, we collectively discuss these proposals as being from ‘the NSW DNSPs’. Their proposed range included:

- Return on debt: 7.6 to 7.8 per cent, based on an immediate transition to the trailing average portfolio return on debt approach
- Return on equity: 10.0 to 11.0 per cent, based on a multiple-model approach

⁴⁷ Ausgrid, Endeavour Energy and Essential Energy have identical rate of return sections in their transitional revenue proposals. Therefore, hereafter a footnote reference to Ausgrid’s transitional revenue proposal relating to rate of return also applies to Endeavour Energy and Essential Energy, unless stated otherwise. Ausgrid, *Transitional regulatory proposal for 1 July 2014 to 30 June 2015*, January 2014, p. 21. Endeavour Energy, *Transitional regulatory proposal to the Australian Energy Regulator*, January 2014, p. 18. Essential Energy, *Transitional regulatory proposal*, January 2014, p. 22.

ActewAGL proposed an indicative rate of return range from 8.8 to 9.5 per cent.⁴⁸ This range included:

- Return on debt: 8.0 per cent, based on an immediate transition to the portfolio cost of debt approach
- Return on equity: 10.0 to 11.8 per cent, based on a multiple-model approach

The DNSPs were required to submit in their TRPs an indicative rate of return range that:⁴⁹

- take into account available market information
- take into account expected market trends
- has regard to the rate of return guidelines published by the AER.

The DNSPs' proposals depart from our rate of return guideline in a number of significant ways. Specifically, where the rate of return guideline specifies a 10 year transition to the trailing average portfolio return on debt approach, the NSW DNSPs and ActewAGL have all proposed to immediately apply a trailing average portfolio.⁵⁰ In estimating the cost of equity, the DNSPs have had significant regard to models including the Fama-French model and a dividend growth model that departs from the AER's preferred form as set out in the guideline.

Much of the information the DNSPs submitted relies on information that was before the AER during the guideline process.⁵¹ Our guideline was made taking into account this and other information and expected market trends and was published in December 2013. Nonetheless, the DNSPs have proposed departures from the guideline. In contrast:

- the Major Energy Users (MEU) submitted that for the transitional year, the WACC should be based on the current approach as applied most recently to SP AusNet.⁵² Further, the MEU submitted it was concerned that the DNSPs have combined estimates from the old and new WACC approaches in a way that results in an increased WACC.⁵³

⁴⁸ ActewAGL, *Transitional regulatory proposal*, January 2014, p. 35.

⁴⁹ NER cl. 11.56.2(b)(2)

⁵⁰ Ausgrid, *Transitional regulatory proposal for 1 July 2014 to 30 June 2015*, January 2014, pp. 21–22.

⁵¹ AER, *Better regulation rate of return guideline*, December 2013.

⁵² Major Energy Users, *NSW electricity distribution revenue reset: Ausgrid application for transition year 2014/15—A response*, February 2010, p. 11; Major Energy Users, *NSW electricity distribution revenue reset: Essential Energy application for transition year 2014/15—A response*, February 2010, p. 11; Major Energy Users, *NSW electricity distribution revenue reset: Essential Energy application for transition year 2014/15—A response*, February 2010, p. 11.

⁵³ Major Energy Users, *NSW electricity distribution revenue reset: Ausgrid application for transition year 2014/15—A response*, February 2010, p. 11; Major Energy Users, *NSW electricity distribution revenue reset: Essential Energy application for transition year 2014/15—A response*, February 2010, p. 11; Major Energy Users, *NSW electricity distribution revenue reset: Essential Energy application for transition year 2014/15—A response*, February 2010, p. 11.

- the Public Interest Advocacy Centre (PIAC) ‘strongly objected’ to proposed departures from the rate of return guideline and supported the application of guideline parameters and approaches in the placeholder determination. In particular, the PIAC noted that the guideline process included a comprehensive consultation process with a broad range of stakeholders, whereas the proposed departures have not been submitted to the same level of rigorous analysis.⁵⁴ Further, on specific parameters, the PIAC made submissions also relevant to the transitional proposals. In particular, it submitted that:
 - we should continue to set the risk free rate as specified in the rate of return guideline, and not using long term historical averages.⁵⁵
 - an equity beta of 0.7 overstates the non-diversifiable risks of an efficient benchmark Australian regulated network company, in light of the supportive regulatory regime. However, while the PIAC accepts the AER’s conclusion, it recommends the adoption of a value no higher than 0.7.⁵⁶
 - while the 6.5 per cent MRP proposed by the NSW DNSPs is consistent with the AER’s point estimate derived during the guideline process, it is inappropriate when combined with a novel approach to estimating the risk free rate and a higher equity beta than set out in the guideline.⁵⁷
 - we should apply the transition to the trailing average portfolio cost of debt approach, as set out in the rate of return guideline. Further, the PIAC submitted that an immediate transition to the portfolio return on debt would result in an unequitable sharing of risks between consumers and NSW/ACT DNSPs.⁵⁸

In light of the extensive consultation and analysis in the rate of return guideline, we consider the NSW/ACT DNSPs have not clearly or sufficiently demonstrated how and why the proposed ranges account for available market information and expected trends. In contrast, we consider the rate of return guideline meets these requirements. Our reasons for this conclusion are set out extensively in the guideline explanatory statement, but in summary:

- we rigorously and consistently assessed a wide range of information that could inform rate of return calculations, including relevant data and recent market trends
- we consulted widely with stakeholders, including consumers, to give us confidence that the final positions satisfied the NEO.

Due to the nature of the transitional review and the task set out in the NER, we have had regard to the rate of return guideline to the extent possible. Specifically, we have applied the value of imputation credits set out in the guideline. Similarly, we have had regard to the guideline approach to estimate the return on debt, although we have yet to finalise selection of a third party data provider as specified in the guideline. As identified below, we have taken account of the RBA data series for the purposes of this placeholder determination. To estimate the return on equity, we have primarily relied on

⁵⁴ Public Interest Advocacy Centre Ltd, *The opening act: PIAC response to the Transitional Regulatory Proposals by the electricity network service providers in NSW for 2014-15*, March 2014, pp. 4–5.

⁵⁵ Public Interest Advocacy Centre Ltd, *The opening act: PIAC response to the Transitional Regulatory Proposals by the electricity network service providers in NSW for 2014-15*, March 2014, pp. 20–21.

⁵⁶ Public Interest Advocacy Centre Ltd, *The opening act: PIAC response to the Transitional Regulatory Proposals by the electricity network service providers in NSW for 2014-15*, March 2014, pp. 23–24.

⁵⁷ Public Interest Advocacy Centre Ltd, *The opening act: PIAC response to the Transitional Regulatory Proposals by the electricity network service providers in NSW for 2014-15*, March 2014, p. 23.

⁵⁸ Public Interest Advocacy Centre Ltd, *The opening act: PIAC response to the Transitional Regulatory Proposals by the electricity network service providers in NSW for 2014-15*, March 2014, pp. 27–30.

application of the foundation model. There are other sources of information that will need to be considered in applying the guideline during the full determination process.

For these reasons, we will use the foundation model as a practical and high-level way to estimate the return on equity for the placeholder determinations.

We have applied the methods and point estimates established in the guideline process. We developed these positions through an extensive consultation process over an extended period. Importantly, we had substantial expert and consumer input to the guideline as well as input from other stakeholders. As a result, it encapsulates an outcome reached after careful consideration and deliberation with stakeholders across the market. We therefore consider that the approaches and principles set out in the guideline meet the NER requirements and are most likely to result in outcomes that are in the long-term interests of consumers.

Employing approaches set out in the guideline we have developed an indicative range to compare against the proposals submitted by the NSW DNSPs and ActewAGL. We developed our indicative range by undertaking the following high level steps:

- Our high level estimate of the return on equity based on the foundation model specified in the guideline is 8.9.⁵⁹ Whilst the CAPM is only one of a number of sources of evidence that we will use to estimate the return on equity, it is the foundation model and is likely to be significant in determining the final estimate. Our high level estimate is made up of:
 - Risk free rate—4.3, based on 10 year commonwealth government security (CGS) yields over a recent 20 day averaging period starting in mid-December 2013.⁶⁰ This was close to the publication of the rate of return guideline, and gives us confidence the estimates are consistent with the same market conditions. However, we also note that the risk free rate has slightly decreased since this time.⁶¹
 - Market risk premium—6.5, based on the rate of return guideline point estimate.⁶²
 - Equity beta—0.7, based on the rate of return guideline point estimate.⁶³
- A return on debt between 6.7 and 7.5. The lower estimate in this range is based on the 7 year Bloomberg BBB rate fair value curve over the same recent 20 day averaging period, extrapolated to 10 years with paired bonds.⁶⁴ The upper estimate in the range is based on the RBA's 10 year return on debt yield.⁶⁵ We are currently reviewing available data sources to estimate the return on debt. In particular, we will assess their suitability for determining the return on debt for regulated service providers.

Combined, this return on debt and cost of equity produces a WACC range of 7.6 to 8.1.

⁵⁹ In line with the rate of return guideline, we have rounded this to one decimal place. See: AER, *Better regulation—Explanatory statement: Rate of return guideline*, December 2013, p. 52.

⁶⁰ Specifically, this was the averaging period used in the recent ACCC draft decision for NSW State Water. See: ACCC *Draft decision on State Water Pricing Application: 2014-15 – 2016-17—Attachments*, March 2014, p. 143.

⁶¹ Specifically, during the 20 business day period from 14 February 2014 to 13 March 2014, the risk free rate was 4.15 per cent.

⁶² AER, *Better regulation—Explanatory statement: Rate of return guideline*, December 2013, p. 93.

⁶³ AER, *Better regulation—Explanatory statement: Rate of return guideline*, December 2013, p. 86.

⁶⁴ Specifically, this was the averaging period used in the recent ACCC draft decision for NSW State Water. See: ACCC *Draft decision on State Water Pricing Application: 2014-15 – 2016-17—Attachments*, March 2014, p. 143.

⁶⁵ We calculated the RBA estimate using a simple average the RBA's spread to CGS values for the end of November 2013, December 2013 and January 2014.

In order to minimise the risk of future price variations, we have applied a WACC of 8.1,⁶⁶ which is the top of our indicative range. This estimate process is not a full application of the rate of return guideline, which is not possible in the timeframe of the transitional review. However, it does give priority to sources of evidence and point estimates that we consider are appropriate for this high level process. While we recognise that the final WACC estimate could be higher or lower than this estimate, we have taken account of current market conditions in preparing this estimate.

Based on this, our analysis indicates that the NSW/ACT DNSPs' proposed rate of return ranges are overstated. Further, we consider that the proposed ranges do not appropriately take into account the available market information and expected market trends reflected in recent debt market data and in the cost of equity analysis set out in the rate of return guideline. Comparing the upper bound of our range (8.1) to the point estimates applied by the NSW/ACT DNSPs to develop the transitional year revenue requirements (8.5 per cent and 8.9 per cent) suggests the NSW/ACT DNSPs have overstated the rate of return by approximately 40 basis points and 80 basis points respectively.

4.2.2 Opening regulatory asset base

Table 4.14 presents an overview of the proposed indicative opening RABs for the NSW/ACT DNSPs as at 1 July 2014. It compares the projected RABs from the 2009 AER distribution determinations against the proposed opening RAB values included in each TRP (reflecting actual capex over the 2009–13 period and estimates for 2013–14, actual depreciation and CPI outcomes). The proposed opening RABs at the start of the transitional regulatory control period for Ausgrid's distribution and transmission networks are 10.8 per cent and 8.8 per cent below the projected values respectively. Endeavour Energy's and Essential Energy's opening RABs are also below the projected values by 7.5 per cent and 11.0 per cent respectively. The primary reason for the lower RABs is that actual capex over the current regulatory control period was lower than forecast.

The opening RAB for ActewAGL's combined distribution and transmission networks is 5.6 per cent higher than the projected value reflecting actual capex being higher than forecast over the current regulatory control period.

We have undertaken a high level review of the proposed inputs in the AER's roll forward model (RFM) used to determine the opening RAB and found that they generally conform to our expectations. For the limited purposes of this placeholder determination, we have adopted the DNSPs' proposed opening RABs for assessing the transitional revenue estimate. Nonetheless, we will have to review these opening RABs for the full determination process.

⁶⁶ Applying a return on debt of 7.5 per cent and a return on equity of 8.9 per cent gives a WACC of 8.06 per cent.

Table 4.14 Proposed opening RAB as at 1 July 2014 in comparison with projection (\$m, nominal)

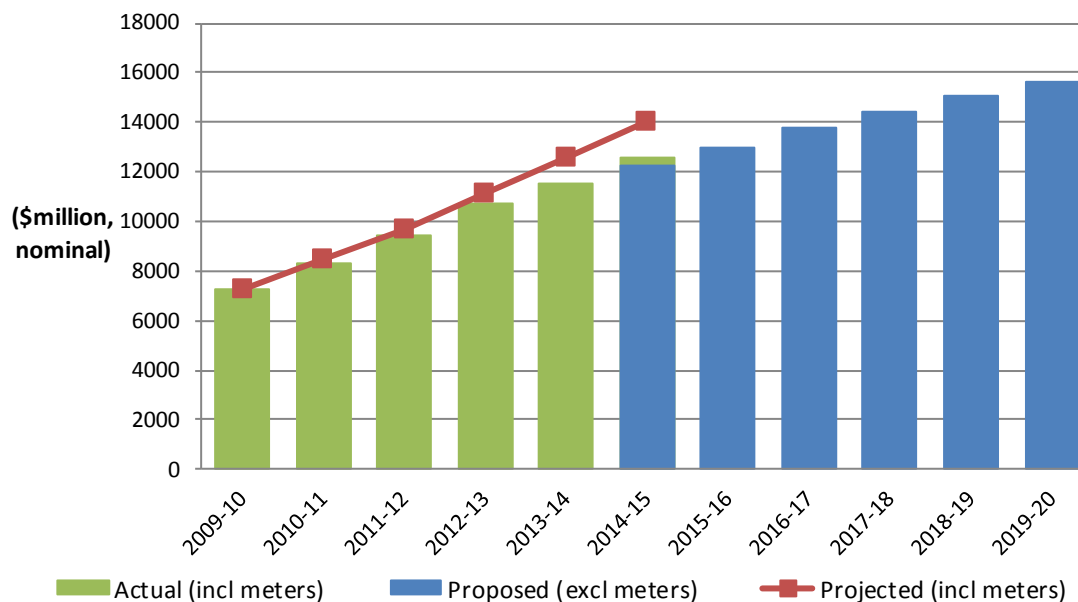
	Projection	Actual	Difference (%)
Ausgrid – distribution	14051	12536	-10.8%
Ausgrid – transmission	2313	2109	-8.8%
Essential Energy	7743	6888	-11.0%
Endeavour Energy	6068	5616	-7.5%
ActewAGL ^a	809	855	5.6%

Source: AER analysis.

Notes: a. At the 2009 determination ActewAGL's distribution and transmission networks were combined. The figures presented represent the combined opening RABs of the two networks.

Figure 4.8 shows the growth in Ausgrid's distribution RAB from 2009 to 2019. At the commencement of the current regulatory control period, Ausgrid's opening distribution RAB was \$7297 million (nominal). Based on the TRP, the opening RAB as at 1 July 2014 is \$12 536 million (nominal). This compares to a RAB at 1 July 2014 of \$14 051 million (nominal), as projected in the 2009 distribution determination. The proposed opening RAB at 1 July 2014 is \$12 280 million (nominal), exclusive of metering assets.⁶⁷ The closing RAB at 30 June 2019 is proposed to be \$15 660 million (nominal), representing an average annual growth rate of 5.0 per cent. This closing RAB is largely driven by the proposed forecast capex as discussed below.

Figure 4.8 Ausgrid's opening RAB, 2009–19 – distribution (\$m, nominal)



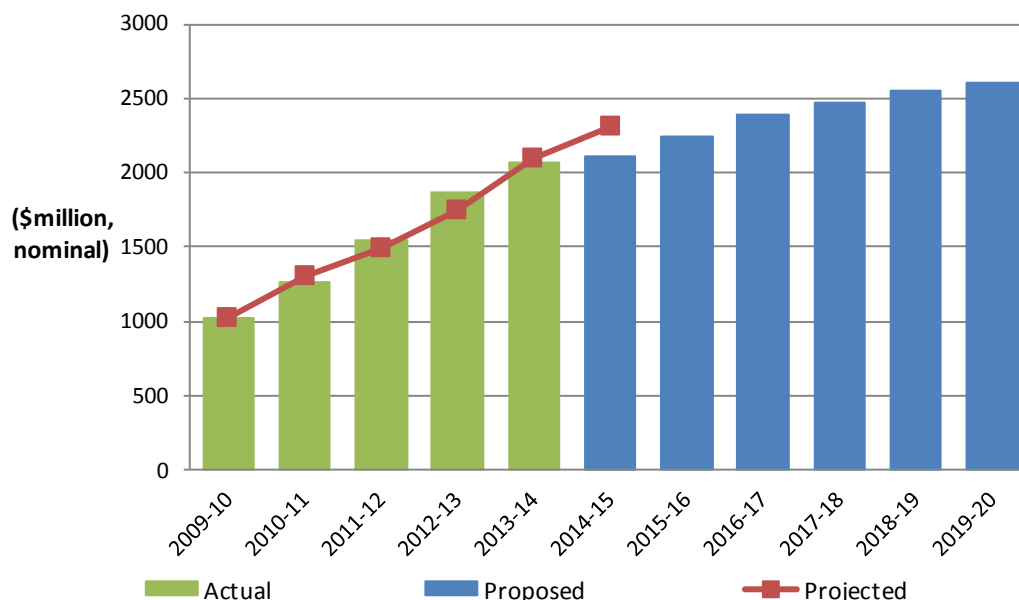
Source: AER analysis.

Figure 4.9 shows the growth in Ausgrid's transmission RAB from 2009 to 2019. At the commencement of the current regulatory control period, Ausgrid's opening transmission RAB was

⁶⁷ From 1 July 2014 metering will be treated as an alternative control service and therefore metering assets are to be excluded from the standard control services RAB.

\$1028 million (nominal). Based on the TRP, the opening RAB as at 1 July 2014 is \$2109 million (nominal). This compares to a RAB at 1 July 2014 of \$2313 million (nominal), as projected in the 2009 determination. The closing RAB at 30 June 2019 is proposed to be \$2610 million (nominal), representing an average annual growth rate of 4.4 per cent. This closing RAB is largely driven by the proposed forecast capex as discussed below.

Figure 4.9 Ausgrid's opening RAB, 2009–19 – transmission (\$m, nominal)

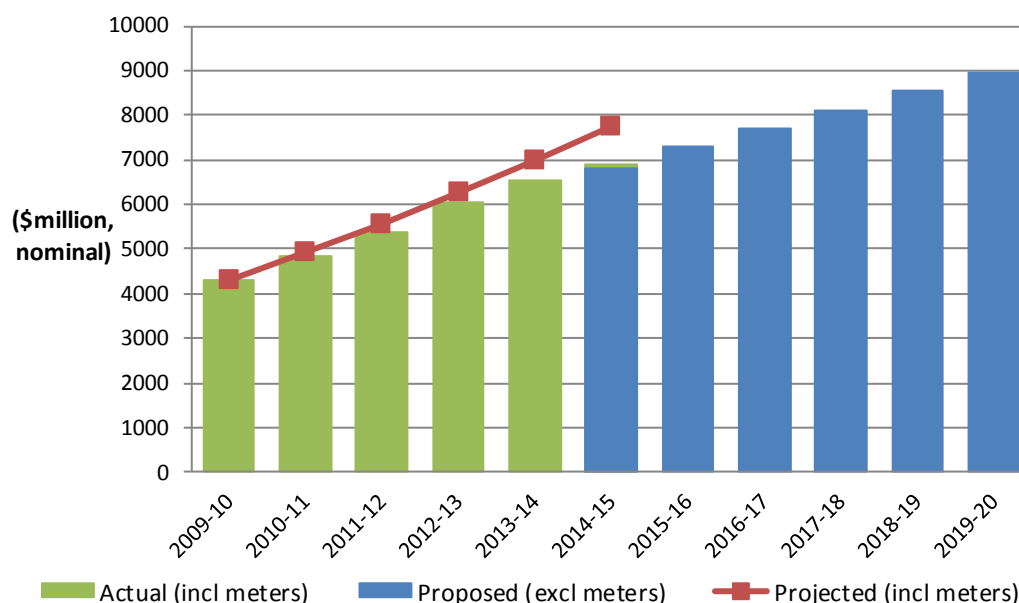


Source: AER analysis.

Figure 4.10 shows the growth in Essential Energy's RAB from 2009 to 2019. At the commencement of the current regulatory control period, Essential Energy's opening distribution RAB was \$4319 million (nominal). Based on the TRP, the opening RAB as at 1 July 2014 is \$6888 million (nominal). This compares to a RAB at 1 July 2014 of \$7743 million (nominal), as projected in the 2009 determination. The proposed opening RAB at 1 July 2014 is \$6790 million (nominal), exclusive of metering assets.⁶⁸ The closing RAB at 30 June 2019 is proposed to be \$8947 million (nominal), representing an average annual growth rate of 5.7 per cent. This closing RAB is largely driven by the proposed forecast capex as discussed below.

⁶⁸ From 1 July 2014 metering will be treated as an alternative control service and therefore metering assets are to be excluded from the standard control services RAB.

Figure 4.10 Essential Energy's opening RAB, 2009–19 (\$m, nominal)

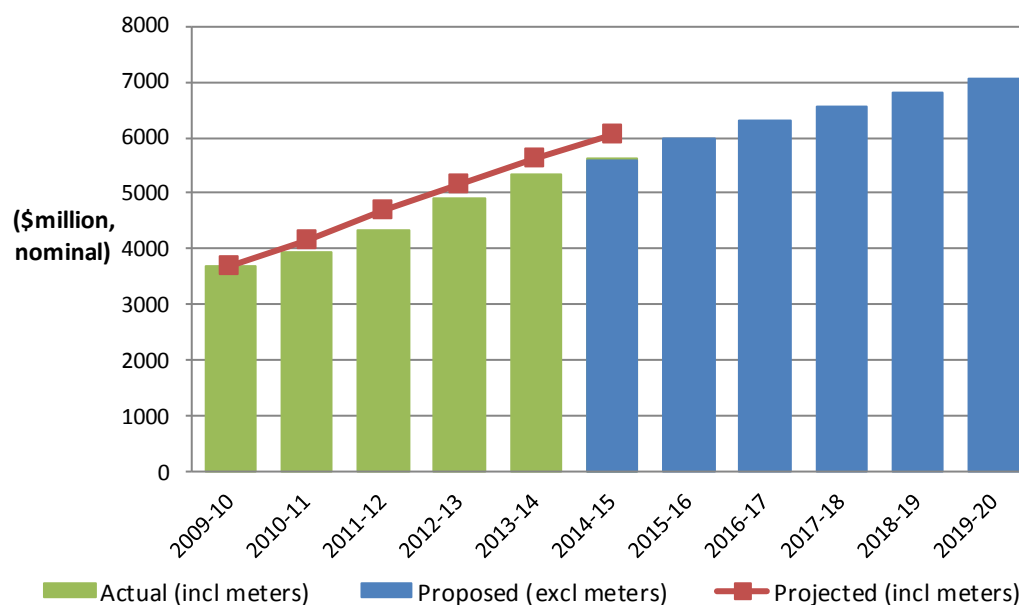


Source: AER analysis.

Figure 4.11 shows the growth in Endeavour Energy's RAB from 2009 to 2019. At the commencement of the current regulatory control period, Endeavour Energy's opening distribution RAB was \$3690 million (nominal). Based on the TRP, the opening RAB as at 1 July 2014 is \$5616 million (nominal). This compares to a RAB at 1 July 2014 of \$6068 million (nominal), as projected in the 2009 determination. The proposed opening RAB at 1 July 2014 is \$5593 million (nominal), exclusive of metering assets.⁶⁹ The closing RAB at 30 June 2019 is proposed to be \$7063 million (nominal), representing an average annual growth rate of 4.8 per cent. This closing RAB is largely driven by the proposed forecast capex as discussed below.

⁶⁹ From 1 July 2014 metering will be treated as an alternative control service and therefore metering assets are to be excluded from the standard control services RAB.

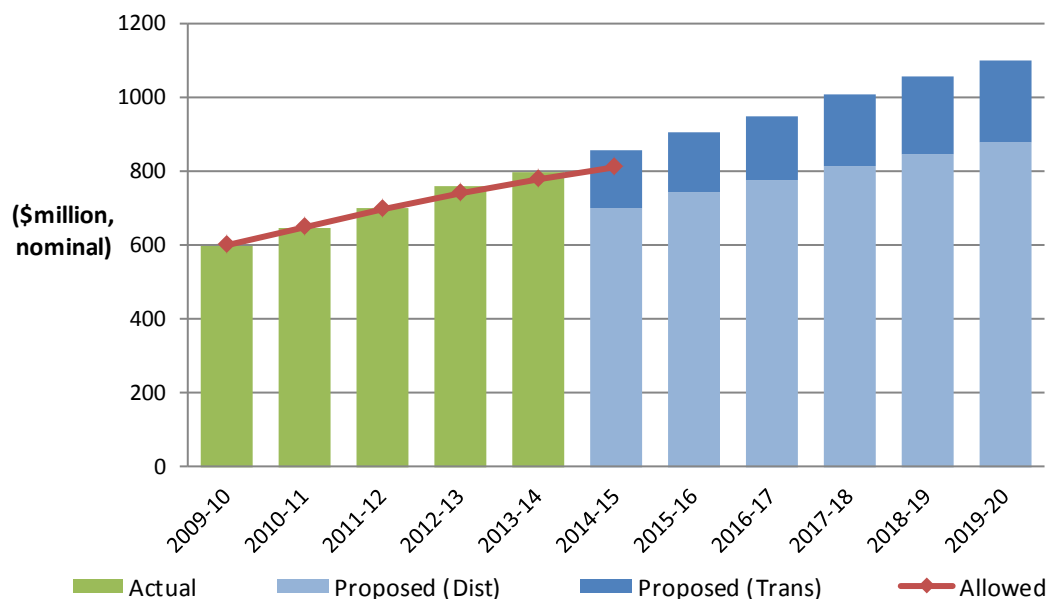
Figure 4.11 Endeavour Energy's opening RAB, 2009–19 (\$m, nominal)



Source: AER analysis.

Figure 4.12 shows the growth in ActewAGL's combined distribution and transmission RAB from 2009 to 2019. At the commencement of the current regulatory control period, ActewAGL's combined opening RAB was \$599 million (nominal). Based on the TRP, the opening RAB as at 1 July 2014 is \$855 million (nominal). This compares to a RAB at 1 July 2014 of \$809 million (nominal), as projected in the 2009 distribution determination. For the transitional and subsequent regulatory control periods ActewAGL's distribution and transmission networks will be treated separately. The opening RAB as at 1 July 2014 for ActewAGL's distribution and transmission networks are \$701 million (nominal) and \$154 million (nominal) respectively. The closing RABs at 30 June 2019 are proposed to be \$881 million (nominal) and \$221 million (nominal) for its distribution and transmission networks respectively. This represents an average annual growth rate of 4.7 per cent for its distribution network and 7.5 per cent for its transmission network. The closing RABs are largely driven by the proposed forecast capex as discussed below.

Figure 4.12 ActewAGL's opening RAB, 2009–19 – distribution and transmission (\$m, nominal)



Source: AER analysis.

4.2.3 Operating and capital expenditure

We have adopted each of the NSW/ACT DNSPs' indicative opex and capex proposals as an input into the placeholder annual revenue requirement for each business. We consider this to be appropriate given the AEMC only intended for this review to be a high level assessment. We also note that given the limited information that the NSW/ACT DNSPs were required to provide in their TRPs, and the time we had to assess these proposals, a more detailed review of opex and capex was not possible.

Also, for the transitional proposals we do not need to review the NSW/ACT DNSPs' forecast capex for the transitional regulatory control period as this does not impact on the revenue estimate for that year.⁷⁰

We will conduct a detailed assessment of each of the NSW/ACT DNSPs' forecast opex and capex as part of our full determination process using the approach outlined in our Expenditure Forecasting Assessment Guideline. We will have regard to all the relevant information in undertaking this assessment including information provided by each of the NSW/ACT DNSPs, stakeholder submissions, and comments from the Consumer Challenge Panel. As part of this process, the AER will apply a range of assessment techniques to test the prudence and efficiency of the NSW/ACT DNSPs' proposals.

Any difference between our placeholder allowance for opex and capex and our allowance for opex and capex determined after our detailed assessment will be reflected in regulated revenues for the subsequent regulatory control period.

⁷⁰ The post-tax revenue modelling approach takes the forecast capex incurred in one year and rolls it into the RAB at the end of the year. So forecast capex only starts receiving a return in the following year.

Appendix B provides a brief summary of:

- each of the NSW/ACT DNSPs' forecast opex for the transitional and subsequent regulatory control periods.
- each of the NSW/ACT DNSPs' capex performance in the current regulatory control period, and their indicative proposed forecast capex for the transitional and subsequent regulatory control periods.

4.2.4 Regulatory depreciation

The DNSPs provided indicative estimates for their forecasts of regulatory depreciation. We do not propose any adjustment to these amounts at this time. A significant driver of regulatory depreciation is the RAB. As discussed in section 4.2.2, we are not making any changes to the proposed RAB for the purposes of this placeholder determination for any DNSP. The proposed asset lives used in the calculation of regulatory depreciation by each DNSP are generally consistent with what we would expect based on previous decisions on the lives of different types of assets and the timing of actual capex. For the limited purposes of this placeholder determination, we have adopted the NSW/ACT DNSPs' proposed asset lives for assessing the transitional revenue estimate. Nonetheless, we will have to review these asset lives for the full determination process.

4.2.5 Cost of corporate income tax

The cost of corporate income tax building block is calculated in the AER's post-tax revenue model (PTRM) and is affected by all inputs. In terms of key inputs into the tax calculation, the NSW/ACT DNSPs have used the AER's RFM to determine their opening tax asset bases and remaining tax asset lives, although Ausgrid was an exception in using its own accounting system to determine the tax asset lives. We also project similar tax asset bases using the RFM and remaining tax asset lives which are broadly consistent with the NSW/ACT DNSPs' proposals. For the limited purposes of this placeholder determination, we have adopted the NSW/ACT DNSPs' proposed opening tax asset bases for assessing the transitional revenue estimate. Nonetheless, we will have to review these inputs for the full determination process.

The DNSPs' proposed corporate income tax allowances for the transitional and subsequent regulatory control periods are significantly higher compared to those in the current regulatory control period. This can be largely explained by all the NSW/ACT DNSPs lowering their estimate of gamma from 0.5 to 0.25. This reduces significantly the amount of tax offsets. In addition, lower interest expenses forecast for the transitional and subsequent regulatory period also reduce the amount of tax offsets for all NSW/ACT DNSPs. Finally, there are business specific factors that lead to the increase in the forecast corporate income tax. For example, ActewAGL has relatively higher revenues (due in part to a higher RAB and higher forecast customer contributions⁷¹) that result in higher cost of corporate income tax.⁷² The increase in corporate income tax for Ausgrid distribution is in part driven by higher revenues from the forecast EBSS reward, which generates no corresponding tax offsets.⁷³ The AER will review these factors as part of the full determination process.

⁷¹ Unlike many other revenue components, customer contributions have no offsetting tax expense associated with them. Therefore a business receives a tax allowance proportional to the tax rate on this revenue component.

⁷² ActewAGL transmission was not regulated separately during the 2009–14 regulatory control period. Therefore there is no historical comparison that can be made of their corporate income tax allowance.

⁷³ Unlike many other revenue components, efficiency rewards have no offsetting tax expense associated with them. Therefore a business receives a tax allowance proportional to the tax rate on this revenue component.

At this time, however, we consider that the gamma input should be amended. The NSW/ACT DNSPs adopted a value of 0.25 for gamma. The DNSPs based their proposals on material that was before the AER during the guideline process. Our assessment of this information is included in our reasoning for our guideline. In contrast to the proposals submitted by the DNSPs, we set out in the rate of return guideline that our estimate of the value of gamma is 0.5 taking into account the information available to us. For these placeholder determinations, we have also taken into account the submission of the PIAC, which supports the use of the gamma value of 0.5 as set out in the AER's guideline.⁷⁴

The use of our estimate reduces the proposed cost of corporate income tax by 50 per cent, rather than 25 per cent as proposed by the DNSPs. We consider that the costs of corporate income tax in the transitional regulatory proposals are overstated based on the extensive analysis in our rate of return guideline. We therefore consider that for the purposes of this high level assessment in this determination, the value of gamma should be changed to 0.5 for these placeholder determinations.

⁷⁴ Public Interest Advocacy Centre, *The opening act: PIAC response to the transitional regulatory proposals by the electricity network service providers on NSW for 2014–15*, March 2014, p. 34.

5 Other constituent decisions

In making our placeholder determination, we must include decisions on the various other matters in accordance with clause 6.12.1 of the NER (as modified by clauses 11.55 and 11.56) and clause 11.56.3 of the NER (the constituent decisions). As appropriate, we have set out our reasons for these decisions below. We note that in respect of several of the constituent decisions, we do not have any discretion. Rather, we must make decisions as set out in the transitional rules.

5.1 D-factor scheme and the Demand Management and Embedded Generation Connection and Incentive Scheme

The rules require us to develop and implement mechanisms to incentivise distributors to consider economically efficient alternatives to building more network.⁷⁵ To meet this requirement, and motivated by the need to improve distributors' capability in the demand management area, we implemented a demand management incentive scheme (DMIS) in our NSW/ACT distribution determinations for the current regulatory period.⁷⁶

The current DMIS for NSW/ACT DNSPs includes two components—the demand management innovation allowance (DMIA)⁷⁷ and the D-factor.⁷⁸

The DMIA is a capped allowance for distributors to investigate and conduct broad-based and/or peak demand management projects. It contains two parts:

- Part A provides for an innovation allowance to be incorporated into each distributor's revenue allowance for opex each year of the regulatory control period. Distributors prepare annual reports on their expenditure under the DMIA⁷⁹ in the previous year, which we then assess against specific criteria.⁸⁰
- Part B compensates distributors for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A. In the current regulatory control period, NSW DNSPs are subject to a weighted average price cap (WAPC) form of control. Under this control mechanism, if a demand management project results in a fall in demand for direct control services, the distributor's recoverable revenues will fall as prices are fixed. For this reason, foregone revenue is recoverable under Part B of the DMIA.

⁷⁵ NER, clause 6.6.3(a).

⁷⁶ The rules have since changed the name to 'Demand Management and Embedded Generation Connection Incentive Scheme' (DMEGCIS) to explicitly cover innovation with respect to the connection of embedded generation. Our current and proposed DMIS include embedded generation. We consider embedded generation to be one means of demand management, as it typically reduces demand for power drawn from a distribution network.

⁷⁷ AER, *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations—Demand management innovation allowance scheme*, 28 November 2008. (AER, *DMIA for ACT and NSW distributors*, Nov 2008).

⁷⁸ AER, *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations—D-factor scheme*, 29 February 2008. (AER, *D-factor for ACT and NSW distributors*, Nov 2008).

⁷⁹ The DMIA excludes the costs of demand management initiatives approved in our determination for the 2009–14 period or under the D-factor scheme.

⁸⁰ AER, *DMIA for ACT and NSW distributors*, Nov 2008, pp. 4–5.

NSW

As set out in the framework and approach paper, we determine that Part A of the DMIA will continue to apply but we determine not to apply either Part B of the DMIA or the D-Factor scheme for NSW distributors in the transitional regulatory control period.⁸¹

We do not apply the Part B foregone revenue component of the DMIA or the D-factor in the transitional regulatory control period due to the move to a revenue cap.

The current innovation allowance amounts will continue in the transitional regulatory control period.

However, as the D-factor operates on a two-year lag, distributors will be able to recover the costs and foregone revenues of applicable demand management projects in the current regulatory control period in the transitional and subsequent regulatory control periods.

ACT

In the current regulatory control period only Part A of the DMIA applies to ActewAGL. We determine to continue applying the DMIA (that is, Part A only) to ActewAGL in the transitional regulatory control period.

5.2 Efficiency Benefit Sharing Scheme

The efficiency benefit sharing scheme (EBSS) provides a continuous incentive for distributors to pursue efficiency improvements in operating expenditure, and provide for a fair sharing of these between distributors and network users. Consumers benefit from improved efficiencies through lower regulated prices.

The transitional rules set out that the EBSS which applied to the NSW/ACT DNSPs under the distribution determinations for their current regulatory control period, will apply to them for the transitional period subject to any modifications set out in the Stage 2 framework and approach paper. These modifications can include non-application of the relevant scheme.⁸²

The EBSS must provide for a fair sharing between distributors and network users of opex efficiency gains and efficiency losses.⁸³ We must also have regard to the following factors in developing and implementing the EBSS:⁸⁴

- 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 need to provide distributors with a continuous incentive to reduce opex
- the desirability of both rewarding distributors for efficiency gains and penalising distributors for efficiency losses

⁸¹ NER, clause 11.56.3(4) provides we must specify that the D-factor scheme and DMIA that applied in the current regulatory control period continue to apply to distributors in the transitional regulatory control period subject to any modifications we set out in the framework and approach paper published for the subsequent regulatory control period. Those modifications may include the non-application of a scheme. The framework and approach paper we published provided for the non-application of the D-factor scheme and Part B of the DMIA in the transitional regulatory control period.

⁸² NER, clause 11.56.3(a)(4).

⁸³ NER, clause 6.5.8(a).

⁸⁴ NER, clause 6.5.8(c).

- any incentives that distributors may have to capitalise expenditure
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

Under the transitional rules we may:⁸⁵

- apply the current EBSS in the transitional period
- apply the current EBSS with modifications
- not apply the EBSS.

In accordance with the approach set out in the Stage 2 framework and approach paper, the AER determines that the EBSS that will apply to the NSW/ACT DNSPs for the transitional regulatory control period will be the same as that applied to the NSW/ACT DNSPs in the current regulatory control period but modified to be in terms of version 2 of the efficiency benefit sharing scheme (the new EBSS) as if the transitional regulatory control period was the first year of the subsequent regulatory control period.⁸⁶

We have taken this approach because:

- We consider it is preferable to apply the new scheme consistently to all network service providers as soon as practicable. The new EBSS and accompanying explanatory statement were published on 29 November 2013.⁸⁷ In developing the new scheme we had regard to the criteria in the rules and took into account stakeholder views. We developed the new EBSS for all network service providers with the intent of applying a nationally consistent approach to incentives for opex performance.
- The EBSS operates on an incremental basis, and performance in one year is related to performance in the previous year. Not applying the EBSS in the transitional period could disrupt the incentives provided by the EBSS to make efficiency gains in other years. Not applying the EBSS to the transitional period also alters the carryover payments a distributor receives. In turn, this alters the sharing of efficiency gains and losses between distributors and consumers. This may have undesirable outcomes for distributors or consumers, inconsistent with the factors we must have regard to in developing and implementing the EBSS. In these circumstances, it is important for the same scheme to apply for the entirety of the transitional and subsequent regulatory control periods as if the transitional regulatory control period was the first year of the subsequent regulatory control period to enable a consistent and workable application of the EBSS.
- The new EBSS revises the approach to adjustments and exclusions. Therefore, applying the current EBSS in the transitional period followed by the new EBSS for the subsequent period could result in exclusions being permitted in the transitional regulatory control period but not in the subsequent regulatory control period, leading to an inconsistent approach to adjustments.

⁸⁵ NER, clause 11.56.3(a)(4).

⁸⁶ AER, *Better Regulation, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013.

⁸⁷ AER, EBSS, Nov 2013; AER, EBSS Explanatory Statement, Nov 2013.

5.3 Service Target Performance Incentive Scheme

Our national distribution STPIS provides a financial incentive to distributors to maintain and improve service performance.⁸⁸ The STPIS provides that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributors' incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with the NEO.

Our national STPIS does not currently apply to the NSW/ACT DNSPs. That is, NSW distributors are not currently subject to financial penalty or reward through an s-factor adjustment to revenue. However, jurisdictional GSL arrangements do apply. At the time of the 2009 determinations, we did not consider the NSW/ACT DNSPs had sufficient relevant historical data to establish service performance targets.⁸⁹

The rules intend for the transitional regulatory control period to be subject to a fast-tracked 'placeholder' determination. There is no formal process for us to outline our proposed application of the STPIS prior to the NSW/ACT DNSPs submitting their TRPs.

In accordance with the Stage 2 framework and approach paper, we determine that no STPIS applies in the transitional regulatory control period to NSW/ACT DNSPs. The current performance reporting obligations will continue to apply with no revenue at risk.

5.4 Capital expenditure sharing scheme

The capital expenditure sharing scheme (CESS) provides financial rewards for DNSPs whose capex becomes more efficient and financial penalties for those that become less efficient. The CESS approximates efficiency gains and efficiency losses by calculating the difference between forecast and actual capex. It shares these gains or losses between distributors and network users. Consumers benefit from improved efficiency through lower regulated prices.

The transitional rules specify that no CESS applies to the NSW/ACT DNSPs for the transitional regulatory control period.⁹⁰

Our transitional decision therefore is that no CESS will apply in the transitional regulatory control period to NSW/ACT DNSPs.

5.5 Small-scale incentive scheme

The rules state that we may develop a small-scale incentive scheme.⁹¹ We have not developed this scheme. In addition, the transitional rules specify that no small-scale incentive scheme applies to the NSW/ACT DNSPs for the transitional regulatory control period.⁹²

Our transitional decision therefore is that no small-scale incentive scheme will apply in the transitional regulatory control period to NSW/ACT DNSPs.

⁸⁸ AER, *Electricity distribution network service providers—service target performance incentive scheme*, 1 November 2009. (AER, *Electricity distribution STPIS*, Nov 2009).

⁸⁹ AER, *Final Decision—New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, p. 244.

⁹⁰ NER, clause 11.56.3(a)(3).

⁹¹ NER, clause 6.6.4.

⁹² NER, clause 11.56.3(a)(3).

5.6 Dual function assets

Our determination for the transitional regulatory period must set out whether we approve or refuse to approve a pricing methodology for transmission standard control services provided by the distributors with their dual function assets.

Dual function assets are high voltage transmission assets forming part of a distribution network. TNSPs usually operate such assets. We must set prices for use of dual function assets under either transmission (chapter 6A of the NER) or distribution (chapter 6 of the NER) pricing rules. In the transitional regulatory period, transmission pricing rules apply to dual function assets operated by Ausgrid and ActewAGL.

For Ausgrid, the transitional rules state that the current application of transmission pricing to its dual function assets will continue for the transitional regulatory period. For ActewAGL, whose dual function assets are new, we set out our decision to apply transmission pricing rules in the transitional regulatory period in our Stage 2 Framework and Approach.⁹³ Endeavour Energy operates dual function assets but transmission pricing does not apply.⁹⁴ Essential Energy does not operate dual function assets.⁹⁵

The rules state that services provided with dual function assets, that if provided by a TNSP would be prescribed transmission services, are deemed to be standard control services. These services are referred to as 'transmission standard control services'. For Ausgrid, the transitional rules state that we must approve for the transitional regulatory period the same pricing methodology we have previously approved for the current regulatory period.⁹⁶

Because ActewAGL does not have a current pricing methodology, it was required to submit one to us with its transitional regulatory proposal.⁹⁷ We must set out in our determination whether we approve or refuse to approve ActewAGL's pricing methodology and reasons for our decision.⁹⁸ If we refuse to approve ActewAGL's proposed pricing methodology, we must include in our determination the proposed pricing methodology with any amendments necessary for us to approve it.⁹⁹

For Ausgrid, consistent with section 11.56.3(12) of the rules, we approve for the transitional regulatory period the same pricing methodology we approved for the current period.¹⁰⁰

For ActewAGL, we approve the pricing methodology submitted by ActewAGL with its transitional regulatory proposal.¹⁰¹ ActewAGL's pricing methodology is consistent with the pricing principles for prescribed transmission services and the pricing methodology guidelines, as required by clause 6A12.3(e) of the rules.

5.7 Classification of services

The NER requires us to specify the same classification of distribution services as that which was decided for the current regulatory control period of the affected DNSP, except to the extent that the Stage 1 framework and approach paper has provided otherwise. Where a classification of a

⁹³ AER, *Stage 2 framework and approach for ActewAGL*, January 2014, p. 10

⁹⁴ AER, *Stage 1 framework and approach paper – Ausgrid, Endeavour Energy and Essential Energy*, March 2013, p. 63

⁹⁵ AER, *Stage 1 framework and approach paper – Ausgrid, Endeavour Energy and Essential Energy*, March 2013, p. 63

⁹⁶ NER, clause 11.56.3(12).

⁹⁷ NER, clause 6A.10.1(e).

⁹⁸ NER, clause 6A.14.1(8).

⁹⁹ NER, clause 6A.13.2(d).

¹⁰⁰ AER, *NSW distribution determination 2009-10 to 2013-14*, April 2009, p. 404.

¹⁰¹ ActewAGL, *Transitional Regulatory Proposal*, Attachment D, January 2014

distribution service has been supplemented or modified in the Stage 1 framework and approach paper, which supplemented or modified classification applies in the transitional regulatory control period.

The placeholder determinations for Ausgrid, Essential Energy, Endeavour Energy and ActewAGL provide a list of the classification of distribution services for the transitional regulatory control period.

5.7.1 Standard control services

Under the NER, we are required to specify the same control mechanisms for standard control services as those which were decided for the determination for the current regulatory control period, except to the extent the Stage 1 framework and approach paper provides otherwise.

For ActewAGL, the same control mechanisms for standard control services as those which were decided for the determination for the current regulatory control period, continue to apply.

For NSW DNSPs, the Stage 1 framework and approach paper provided that different control mechanisms for standard control services would apply in the transitional regulatory control period. The control mechanisms to apply to NSW DNSPs for standard control services are therefore the control mechanisms set out in the Stage 1 framework and approach paper.

The formulae that gives effect to this control mechanism is also set out in the Stage 1 framework and approach paper. In accordance with clause 11.56.3(5) and (7) the control mechanism has been specified in each of the NSW DNSPs' placeholder determinations. The control mechanism formulae will apply throughout both the transitional regulatory control period and the subsequent regulatory control period. This ensures that the new revenue cap control mechanism can be implemented consistently across the five years of the combined regulatory control periods. The revenue cap formulae allows for adjustments to be made in future years to take account of specific matters that have arisen in previous years. In the transitional year, the revenues that DNSPs are entitled to recover from providing standard control services to users is limited to the annual revenue requirement we have approved in the placeholder determinations.

5.7.2 Alternative control services

Alternative control services are regulated distribution services other than standard control services. They are usually customer specific or customer requested services charged on a 'user pays' principle. Alternative control services include, but are not limited to, public lighting and ancillary network services.

Under the NER, we are required to specify the same control mechanisms for alternative control services as those which were decided for the determination for the current regulatory control period, except to the extent the Stage 1 framework and approach paper provides otherwise.

As set out in the Stage 1 framework and approach paper, the form of control mechanism for alternative control services are price caps for individual services. This is the same control mechanism as used in the 2009–14 regulatory control period.

Where services (however classified) had prices in the current regulatory control period, and they are classified as alternative control services for the transitional regulatory control period, the prices must be escalated by CPI in the transitional regulatory control period.¹⁰²

The DNSPs have proposed to escalate 2013–14 service prices by an expected inflation rate of 2.5 per cent. This is compliant with the rules. We approve alternative control service prices provided in the transitional regulatory proposals by the NSW/ACT DNSPs where these prices have been escalated by CPI.

Some alternative control services do not have individual prices. This is the case if it is a new service or a service that was previously part of a bundled service for which no separate price is currently charged (such is the case with types 5–6 metering).

For alternative control services that currently do not have an individual price, we accept the approaches to pricing proposed by each of the NSW/ACT DNSPs.

Compliance with the control mechanisms for alternative control services for the transitional regulatory control period will be the same as for the 2009–14 regulatory control period for all DNSPs.

5.8 Cost pass throughs

The pass through mechanism of the NER recognises that a DNSP can be exposed to risks beyond its control, which may have a material impact on its costs. A cost pass through enables a business to recover (or pass through) the costs of defined unpredictable, high cost events that are not built into the placeholder determination. A number of pass through events are set out expressly in the NER.

The additional pass through events that are to apply for the transitional regulatory control period are set out in transitional rules.¹⁰³ They are the same additional pass through events that were decided in the distribution determination for the current regulatory control period, specifically:

- For Ausgrid:
 - retail project event
 - smart meter event
 - emissions trading scheme event
 - general nominated pass through event
- For Endeavour Energy:
 - retail project event
 - smart meter event
 - emissions trading scheme event
 - general nominated pass through event
- For Essential Energy:

¹⁰² NER, clause 11.56.3(j)

¹⁰³ NER, clause 11.56.3(a)(8)

- retail project event
- smart meter event
- emissions trading scheme event
- aviation hazards event
- general nominated pass through event

as defined in the AER's 2009–14 NSW distribution determination.

- For ActewAGL
 - feed-in tariff direct payment event
 - smart meter event
 - emissions trading scheme event
 - general nominated pass through event

as defined in the AER's 2009–14 ACT distribution determination.

The transitional rules also state that the AER is to include the "terrorism event" as an additional pass through event. For the current regulatory control period, there was a pass through event for all NSW/ACT DNSPs known as the terrorism event.

The terrorism event was removed from the list of events that constitute pass through events by the *National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012*. Prior to its removal, the 'terrorism event' was defined as:

an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which materially increases the costs to a Transmission Network Service Provider of providing prescribed transmission services or the costs to a Distribution Network Service Provider of providing direct control services.

As a transitional measure, the NER provides for the terrorism event to continue to constitute a pass through event during the transitional regulatory control period. In the subsequent regulatory control period, it will no longer automatically constitute a pass through event.

5.9 Connection policies

The connection policy sets out the circumstances in which the DNSP may require a connection applicant to pay a connection charge and explains how such a charge is determined. We may approve the proposed connection policy if satisfied that the proposed policy adequately complies with the requirements of Part DA of chapter 6 of the NER.

The purpose of our connection charge guidelines for electricity retail customers is to ensure that connection charges:

- are reasonable, taking into account the efficient costs of providing the connection services arising from the new connection or connection alteration
- provide, without undue administrative cost, a user-pays signal to reflect the efficient cost of providing the connection services
- limit cross-subsidisation of connection costs between different classes (or subclasses) of retail customer
- are competitively neutral, if the connection services are contestable.

Part DA of Chapter 6 of the NER requires a DNSP to prepare a connection policy for approval by the AER. The proposed connection policy:¹⁰⁴

- must be consistent with:
 - the connection charge principles set out in chapter 5A of the NER; and
 - the connection charge guidelines published by us under chapter 5A.¹⁰⁵
- must specify:
 - the categories of persons that may be required to pay a connection charge and the circumstances in which such a requirement may be imposed; and
 - the aspects of a connection service for which a connection charge may be made; and
 - the basis on which connection charges are determined; and
 - the manner in which connection charges are to be paid (or equivalent consideration is to be given); and
 - a threshold (based on capacity or any other measure identified in the connection charge guidelines) below which a retail customer (not being non-registered embedded generator or a real estate developer) will not be liable for a connection charge for an augmentation other than an extension.

5.9.1 Method for assessing connection policy

We examined the connection policies provided in the TRPs and assessed them against the requirements of the NER and our connection charge guideline for electricity retail customers. We identified a number of inconsistencies between the proposed connection policies, and our connection charge guideline and the connection charge principle. We provided comments to the NSW/ACT DNSPs, and sought them to clarify and resolve these inconsistencies. Each of the NSW/ACT DNSPs provided us with revised transitional distribution connection policies in response to our requests.

¹⁰⁴ NER, clause 6.7A.1(b).

¹⁰⁵ AER, *Connection charge guideline for electricity retail customers, Under chapter 5A of the National Electricity Rules Version 1.0*, June 2012.

Ausgrid

We approve Ausgrid's revised transitional distribution connection policy for connection charges as it meets the requirements under Part DA of Chapter 6 of the NER. It is also consistent with the connection charge principles and the AER's connection charge guidelines for electricity retail customers. Appendix B in Ausgrid's 2014–15 Determination contains the revised connection policy to apply to Ausgrid for the transitional regulatory control period.

Our initial review of Ausgrid's transitional distribution connection policy identified several minor issues. These issues were consequently clarified and resolved by Ausgrid. Broadly these minor issues included:¹⁰⁶

- The proposed minimum refund threshold in appendix D2.6 of the proposed connection policy requires clarification to be consistent with clause 6.1.3 of the connection charge guidelines.
- Its proposed calculation method for refunds to pioneer customers does not take into account asset depreciation, which is required under clause 6.1.2 of the connection charge guidelines.

Ausgrid submitted its revised connection policy on 15 March 2014, which addressed our previous concerns.¹⁰⁷ We have reassessed its revised transitional connection policy and consider that it meets the requirements under Part DA of Chapter 6 of the NER. It is also consistent with the connection charge principles and the AER's connection charge guidelines for electricity retail customers.

Essential Energy

We approve Essential Energy's revised transitional distribution connection policy for connection charges as it meets the requirements under Part DA of Chapter 6 of the NER. It is also consistent with the connection charge principles and the AER's connection charge guidelines for electricity retail customers. Appendix B in Essential Energy's 2014-15 Placeholder Determination contains the revised connection policy to apply to Essential Energy for the transitional regulatory control period.

Our initial review of Essential Energy's transitional distribution connection policy identified several minor issues. These issues were consequently clarified and resolved by Essential Energy. Broadly these minor issues included:¹⁰⁸

- Essential Energy proposed an upfront payment when the total ancillary services fees is greater than \$5000. This is contrary to clause 9.1.1 of the connection charge guidelines, which only allows the DNSP to charge a prepayment for the amount less than \$5000.
- The proposed minimum refund threshold in section 6.4 requires clarification to be consistent with clause 6.1.3 of the connection charge guidelines.
- The depreciation calculation formula in relation to the proposed pioneer scheme contains a small error and does not reflect Essential Energy's policy statement in this regard.

Essential Energy submitted its revised connection policy on 18 March 2014, which addressed our previous concerns.¹⁰⁹ We have reassessed its revised transitional connection policy and consider that it meets the requirements under Part DA of Chapter 6 of the NER. It is also consistent with the

¹⁰⁶ AER, *Information request: AER AUSG TRP compliance 001 – connection policy*, 6 March 2014.

¹⁰⁷ Ausgrid, *Re: Information request: AER AUSG TRP compliance 001 – connection policy*, 15 March 2014.

¹⁰⁸ AER, *Information request: AER ESSE TRP compliance 001 – connection policy*, 6 March 2014.

¹⁰⁹ Essential Energy, *Re: Typo in the connection policy*, 18 March 2014.

connection charge principles and the AER's connection charge guidelines for electricity retail customers.

Endeavour Energy

We approve Endeavour Energy's revised transitional distribution connection policy for connection charges as it meets the requirements under Part DA of Chapter 6 of the NER. It is also consistent with the connection charge principles and the AER's connection charge guidelines for electricity retail customers. Appendix B in Endeavour Energy's 2014-15 Determination contains the revised connection policy to apply to Endeavour Energy for the transitional regulatory control period.

Our initial review of Endeavour Energy's transitional distribution connection policy identified several issues. These issues were consequently resolved by Endeavour Energy. Broadly these issues included:¹¹⁰

- The proposed connection policy did not reflect the full context of the guideline requirements in relation to the Pioneer Scheme of the AER's connection charge guidelines.
- Endeavour did not adequately specify a threshold below which a retail customer will not be liable for a connection charge in accordance with clause 6.7A.1(b)(2)(v) of the NER. In particular, it did not distinguish the differences between extension and shared network augmentation.
- The proposed connection policy did not clarify whether there are separate connection charges for extension and augmentation and under what circumstances these charges apply. This is required under clause 6.7A.1(b)(2)(ii) of the NER.
- Endeavour included sections on security fees which are different to the security fees contemplated under chapter 5A and the AER's connection charge guideline. According to clause 10.1.2 of the AER's connection charge guidelines, a security fee refers to a fee that is payable by the applicant if a DNSP fairly and reasonably assesses that there is a high risk that the DNSP may not earn the estimated incremental revenue. However, Endeavour's policy referred to guarantees of Accredited Service Provider's (ASP's) work.
- The proposed reimbursement to Endeavour's pioneer scheme does not reflect the full context of the guideline's requirements. For example:
 - Endeavour noted the reimbursement scheme only applies to rural and large load customers. This is inconsistent with clause 6.1.1 of the guideline.
 - The section that required customers to indicate their involvement with the reimbursement scheme appears unreasonable.
 - Its proposed calculation of the refund for the reimbursement of Endeavour's pioneer scheme does not take into account asset depreciation, which is required under clause 6.1.2 of the connection charge guidelines.
- The proposed connection policy did not adequately define the relevant criteria of the connection services on offer and how they will apply, which is required under clause 6.7A.1(b)(2)(i) of the NER.

¹¹⁰ AER, *Information request: AER ENDE TRP compliance 001 – connection policy*, 6 March 2014.

- We consider those sections that set out Endeavour’s contractual processes are not relevant for including into the connection policy.

Endeavour Energy submitted its revised connection policy on 21 March 2014, which addressed our previous concerns.¹¹¹ We have reassessed its revised transitional connection policy and consider that it meets the requirements under Part DA of Chapter 6 of the NER. It is also consistent with the connection charge principles and the AER’s connection charge guidelines for electricity retail customers.

ActewAGL

We approve ActewAGL’s revised transitional distribution connection policy for connection charges as it meets the requirements under Part DA of Chapter 6 of the NER. It is also consistent with the connection charge principles and the AER’s connection charge guidelines for electricity retail customers. Appendix B in ActewAGL’s 2014-15 Determination contains the revised connection policy to apply to ActewAGL for the transitional regulatory control period.

Our initial review of ActewAGL’s transitional distribution connection policy identified several minor issues. These issues were consequently clarified and resolved by ActewAGL. Broadly these minor issues included:

- We considered that ActewAGL’s transitional distribution connection policy should clarify how “major connections” and “minor or routine connection” services relate to basic, standard and negotiated connection offers under chapter 5A of the NER.
- Although not mandatory, we believe that when calculating the refund amount for the pioneer scheme, ActewAGL should take into account the time and value of money that the customers who funded the connection asset paid.¹¹²
- We noted that ActewAGL did not include a rate (\$/kVA) for its shared network asset augmentation charge or the method that it would apply to calculate this charge in its proposed transitional connection policy.¹¹³

ActewAGL submitted its revised connection policy on 28 March 2014, which addressed our previous concerns. We have reassessed ActewAGL’s revised transitional connection policy and consider that it meets the requirements under Part DA of Chapter 6 of the NER. It is also consistent with the connection charge principles and the AER’s connection charge guidelines for electricity retail customers.

¹¹¹ Endeavour Energy, *Connection policy final to AER.docx*, 21 March 2014

¹¹² Chapter 5A of the NER require DNSPs to operate a pioneer scheme which requires them to make refunds to retail customers who funded connection assets within 7 years which are no longer being dedicated to the exclusive use of that customer.

¹¹³ AER, *Connection charge guideline for electricity retail customers, Under chapter 5A of the National Electricity Rules Version 1.0*, June 2012, clause 5.2.8 states that a DNSP’s unit rate(s) for the cost of augmentation (insofar as it involves more than an extension) must be approved by the Australian Energy Regulator in its distribution determination before being applied by the distribution network service provider.

Part 2 – Appendices

A Submissions

Table A.1 Submissions on Ausgrid's TRP

Date	Respondent
3 March 2014	The National Generators Forum (NGF)
4 March 2014	Major Energy Users Inc (MEU)
4 March 2014	The Public Interest Advocacy Centre (PIAC)
5 March 2014	Vector Limited

Table A.2 Submissions on Endeavour Energy's TRP

Date	Respondent
3 March 2014	The National Generators Forum (NGF)
4 March 2014	Major Energy Users Inc (MEU)
4 March 2014	The Public Interest Advocacy Centre (PIAC)
5 March 2014	Vector Limited

Table A.3 Submissions on Essential Energy's TRP

Date	Respondent
3 March 2014	Cotton Australia
3 March 2014	NSW Irrigators' Council (NSWIC)
3 March 2014	The National Generators Forum (NGF)
4 March 2014	Major Energy Users Inc (MEU)
4 March 2014	The Public Interest Advocacy Centre (PIAC)
5 March 2014	Vector Limited

Table A.4 Submissions on ActewAGL's TRP

Date	Respondent
3 March 2014	The Australian National University
5 March 2014	Vector Limited

B Summary of the NSW/ACT DNSPs' transitional regulatory proposals

B.1 Ausgrid

B.1.1 Total revenue

Table B.1 and Table B.2 show Ausgrid's proposed total revenue for each year of the 2014–19 period for its distribution and transmission networks respectively. The total revenue is broken up by its constituent building blocks and shows Ausgrid's proposed revenue smoothing.

Table B.1 Ausgrid's proposed building blocks and total revenue – distribution (\$m, nominal)

Building blocks	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Return on capital		1047	1107	1172	1229	1285
Return of capital		118	141	163	149	162
Operating expenditure		551	551	591	570	577
Efficiency carryover		95	116	83	138	-
Net tax allowance		105	113	129	128	133
Total revenue (unsmoothed)		1916	2028	2138	2213	2157
Total revenue (smoothed)	2109	2004	2044	2085	2126	2171
Metering revenue		72	78	84	80	82
Total bundled revenue (smoothed)	2109	2076	2122	2168	2206	2253
Change ^a (%)		-1.5%	2.2%	2.2%	1.7%	2.1%

Source: Ausgrid, *Transitional regulatory proposal*, January 2014. Ausgrid, *Post-Tax Revenue Model*, January 2014.

Notes: Numbers may not sum due to rounding.

a. This row shows the year-on-year change in total nominal revenues. It should not be interpreted as the X-factor change from year to year.

Table B.2 Ausgrid's proposed building blocks and total revenue – transmission (\$m, nominal)

Building blocks	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Return on capital		180	192	204	210	218
Return of capital		12	16	20	17	19
Operating expenditure		42	42	45	43	44
Efficiency carryover		7	9	6	10	0
Net tax allowance		13	14	16	15	16
Total revenue (unsmoothed)		254	272	290	296	296
Total revenue (smoothed)	268	270	275	281	286	292
Change ^a (%)		0.5%	2.0%	2.0%	2.0%	2.0%

Source: Ausgrid, *Transitional regulatory proposal*, January 2014. Ausgrid, *Post-Tax Revenue Model*, January 2014.

Notes: Numbers may not sum due to rounding.

a. This row shows the year-on-year change in total nominal revenues. It should not be interpreted as the X-factor change from year to year.

In its TRP, Ausgrid stated that it has an expected under-recovery of revenues from 2013–14 of \$19.8 million. This amount is to be recovered in the transitional regulatory control period.¹¹⁴

The key determinants of the building blocks from Ausgrid's TRP (opex, capex, rate of return and RAB) are separately presented below. Ausgrid's TRP also included details on:

- Regulatory depreciation—Ausgrid proposed to use straight-line depreciation as calculated in the PTRM, and put forward a schedule of asset lives. Its depreciation forecasts (including the net effect of indexation) are included in the RAB roll forward tables presented below.
- Cost of corporate income tax—Ausgrid submitted taxation calculations using the PTRM, which involves calculating the indicative tax payable and then reducing its tax allowance with respect to the value of imputation credits. Ausgrid's proposed gamma figure (assumed value of imputation credits) is discussed below in the rate of return section.
- Efficiency carryovers—Ausgrid proposed a positive carryover allowance reflecting past efficiency gains associated with its opex (under the EBSS) over the current regulatory control period.
- Metering revenue—Ausgrid has proposed a revenue allowance to recover the costs of providing distribution metering services in its TRP. Metering services will be unbundled from standard control services from 1 July 2014 to alternative control services. However, the transitional rules require Ausgrid to recover the costs of providing these services as part of standard control services for the transitional regulatory control period. For the subsequent regulatory control period metering costs will not be recovered via Ausgrid's standard control services revenue.

¹¹⁴ Ausgrid, *Transitional regulatory proposal*, p. 26.

B.1.2 Rate of return

Ausgrid proposed an indicative WACC range of 8.5–9.1 per cent for the transitional regulatory control period.¹¹⁵ This indicative WACC range reflects the parameters shown in Table B.3

Ausgrid considered multiple models and estimation methods in estimating the return on equity, before adopting a long-term average approach to arrive at a point estimate.¹¹⁶ Ausgrid submitted that their approach is consistent with the requirement to have regard to relevant estimation methods, financial models, market data and other evidence when determining the allowed rate of return.¹¹⁷ Ausgrid's return on equity estimates are based on a report commissioned in January 2014 by the Competition Economists Group (CEG).¹¹⁸

Ausgrid proposed to adopt a trailing average portfolio approach (with a 10-year debt term and BBB+ credit rating) to estimate the return on debt as set out in our rate of return guideline.¹¹⁹ However, they submitted that historical rates would best match their actual debt financing practices (the immediate adoption of a trailing average debt portfolio).¹²⁰

Ausgrid adopted a value of 0.25 for imputation credits (gamma).¹²¹

Table B.3 Ausgrid's proposed WACC parameters for the transitional regulatory control period

	NSW DNSPs
Risk free rate	4.8–5.2 (4.8)
Market risk premium	6.5
Equity beta	0.8
Cost of equity	10.0–11.0 (10.0)
Debt risk premium	2.7–2.8 (2.8)
Cost of debt	7.6–7.8 (7.6)
Gamma	0.25
Nominal vanilla WACC	8.5–9.1 (8.5)

Source: Ausgrid, *Transitional revenue proposal*, January 2014. ActewAGL, *Transitional revenue proposal*, January 2014. Ausgrid, *Post-tax revenue model*, January 2014. ActewAGL, *Post-tax revenue model*, January 2014.

Note: Where the service provider submitted a range for a parameter, the table includes the range and the final proposed value (in parentheses).

¹¹⁵ Ausgrid, Endeavour Energy and Essential Energy have identical rate of return sections in their transitional revenue proposals. Therefore, hereafter a footnote reference to Ausgrid's transitional revenue proposal relating to rate of return also applies to Endeavour Energy and Essential Energy, unless stated otherwise. Ausgrid, *Transitional regulatory proposal for 1 July 2014 to 30 June 2015*, January 2014, p. 21. Endeavour Energy, *Transitional regulatory proposal to the Australian Energy Regulator*, January 2014, p. 18. Essential Energy, *Transitional regulatory proposal*, January 2014, p. 22.

¹¹⁶ Ausgrid, *Transitional regulatory proposal*, January 2014, p. 22.

¹¹⁷ NER, clause 6.5.2(e)(1).

¹¹⁸ CEG, *WACC estimates*, January 2014.

¹¹⁹ AER, *Better regulation rate of return guideline*, December 2013.

¹²⁰ Ausgrid, *Transitional regulatory proposal*, January 2014, p. 21.

¹²¹ Ausgrid, *Post-tax revenue model*, January 2014.

B.1.3 RAB

The opening RAB at 1 July 2014 is a key determinant of the allowed revenue for the transitional regulatory control period. It directly influences the return on capital and return of capital building blocks. Table B.4 and Table B.5 show Ausgrid's proposed roll forward of its distribution and transmission RABs respectively across the 2009–14 regulatory control period in order to derive the opening RABs.

Table B.4 Derivation of Ausgrid's opening RAB as at 1 July 2014 – distribution (\$m, nominal)

RAB	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	7297	8297	9471	10757	11551
Net capital expenditure	1129	1247	1335	1037	753
Straight-line depreciation	-262	-309	-370	-433	-446
Inflation adjustment	133	236	321	190	289
Closing RAB	8297	9471	10757	11551	12147
Net adjustments from 2008–09					390
Opening RAB as at 1 July 2014					12536

Source: Ausgrid, *Roll Forward Model*, January 2014.
Notes: Numbers may not sum due to rounding.

Table B.5 Derivation of Ausgrid's opening RAB as at 1 July 2014 – transmission (\$m, nominal)

RAB	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	1028	1264	1545	1863	2063
Net capital expenditure	235	276	340	212	167
Straight-line depreciation	-29	-37	-48	-59	-63
Inflation adjustment	30	42	25	47	52
Closing RAB	1264	1545	1863	2063	2218
Net adjustments from 2008–09					-108
Opening RAB as at 1 July 2014					2109

Source: Ausgrid, *Roll Forward Model*, January 2014.
Notes: Numbers may not sum due to rounding.

Table B.4 and Table B.5 also include adjustments that relate to 2008–09. When the AER made its determination for the current regulatory control period, final figures for 2008–09 could not be obtained (since the year was not yet complete). Hence, Ausgrid's proposal adjusts for the difference between actual and estimated capex for the 2008–09 financial year.

Table B.6 and Table B.7 show Ausgrid's proposed roll forward of the RABs from 1 July 2014 to 30 June 2019 for its distribution and transmission networks respectively. This builds on the proposed capex outlined above.

Table B.6 Ausgrid's proposed RAB 2014–19 – distribution (\$m, nominal)

RAB	2014–15	2015–16	2016–17	2017–18	2018–19
Opening RAB	12280	12988	13756	14421	15081
Net capital expenditure	827	909	828	809	749
Straight-line depreciation	-425	-466	-507	-509	-539
Inflation adjustment ^a	307	325	344	361	377
Closing RAB	12988	13756	14421	15081	15668

Source: Ausgrid, *Post-Tax Revenue Model*, January 2014.

Notes: Numbers may not sum due to rounding.

a. Based on a forecast inflation rate of 2.50 per cent per annum.

Table B.7 Ausgrid's proposed RAB 2014–19 – transmission (\$m, nominal)

RAB	2014–15	2015–16	2016–17	2017–18	2018–19
Opening RAB	2109	2247	2390	2468	2553
Net capital expenditure	150	159	98	102	77
Straight-line depreciation	-65	-72	-80	-78	-83
Inflation adjustment ^a	53	56	60	62	64
Closing RAB	2247	2390	2468	2553	2611

Source: Ausgrid, *Post Tax-Revenue Model*, January 2014.

Notes: Numbers may not sum due to rounding.

a. Based on a forecast inflation rate of 2.50 per cent per annum.

Although the roll forward of the RAB across this period has little direct impact on the revenue for the transitional regulatory control period, it has a larger impact on subsequent years. Hence, it is relevant to our assessment of the likely price variations that will occur across the entire 2014–19 period.

B.1.4 Operating expenditure

Ausgrid has used the actual opex of 2012–13 as its base year. To derive forecast opex for 2014-15 to 2018-19 Ausgrid has added opex for the following factors:

- Forecast changes in labour costs¹²²
- Loss of synergy from the sale of associated retail service providers¹²³
- The impact of reductions capex on opex requirements including the impact of a reduced capex program on its cost structures.¹²⁴

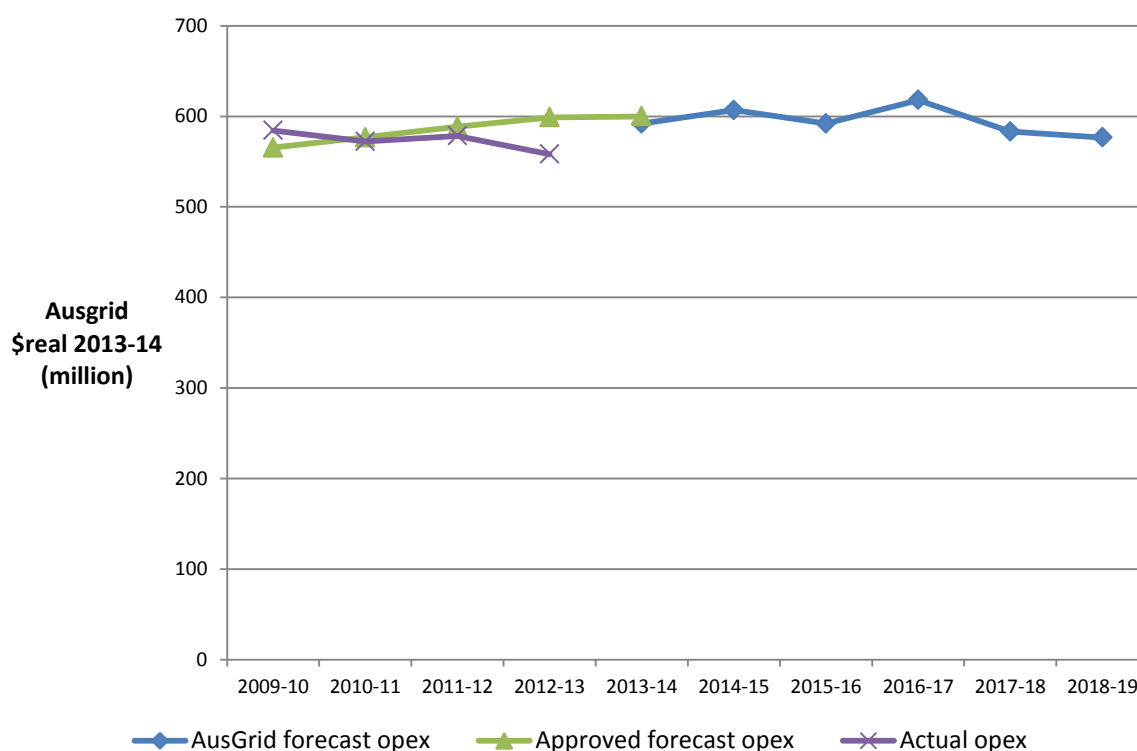
¹²² Ausgrid, *Transitional revenue proposal 2014/15*, 31 January 2014, pp. 31-32; Endeavour Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 34; Essential Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 37.

¹²³ Ausgrid, *Transitional revenue proposal 2014/15*, 31 January 2014, pp. 31-32; Endeavour Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 35; Essential Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 37.

- Additional cost of inspecting private mains to comply with our legislative and regulatory obligations¹²⁵
- Leaseback cost of one of its corporate buildings that is forecast to be sold by 30 June 2014¹²⁶

Ausgrid has also forecast productivity improvements to offset some of the cost increases identified above.

Figure B.1 Comparison of Ausgrid's forecast opex to its recent actual opex



Source: Ausgrid, *Transitional regulatory proposal*, p.29.

B.1.5 Capital expenditure

Ausgrid's actual total capex spend for its distribution assets was around 24 per cent less than its forecast capex over the 2009–14 regulatory control period. It spent \$5805 million (\$2013–14) compared with a capex allowance of \$7677 million (\$2013–14). This is an underspend of \$1872 million. As shown in Figure B.2, the majority of this underspend was in the final 2 years of the regulatory control period where Ausgrid spent 32.3 per cent and 54.5 per cent under its allowance respectively.¹²⁷

Ausgrid's actual total capex on its transmission assets spend was around 9 per cent less than its forecast capex over the 2009–14 regulatory control period. It spent \$1239 million (\$2013-14) compared with a capex allowance of \$1359 million (\$2013–14). This is an underspend of \$120 million.

¹²⁴ Ausgrid, *Transitional revenue proposal 2014/15*, 31 January 2014, p. 33; Endeavour Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 35; Essential Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 37.

¹²⁵ Ausgrid, *Transitional revenue proposal 2014/15*, 31 January 2014, pp. 31-32.

¹²⁶ Ausgrid, *Transitional revenue proposal 2014/15*, 31 January 2014, pp. 31-32.

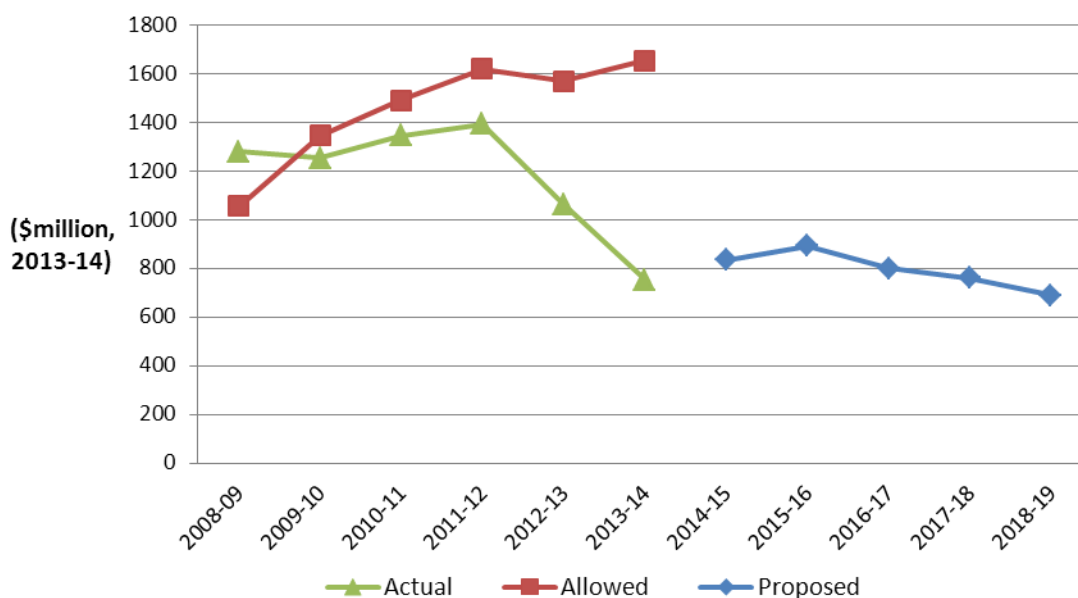
¹²⁷ Note that the capex amount for the final year of the regulatory control period is an estimate.

As shown in Figure B.3, Ausgrid underspent on capex for its transmission assets in the first and last years by over 40 per cent but overspent its allowance in 2011–12 by 46.4 per cent.¹²⁸

Ausgrid’s indicative proposed total forecast distribution capex for the 2014–19 period is \$3974 million (\$2013–14).¹²⁹ This is \$3703 million (\$2013–14), or 48 per cent, lower than its allowed capex for the 2009–14 regulatory control period. It is \$1831 million (\$2013–14), or 31 per cent less than Ausgrid’s actual total capex spend over the 2009–14 regulatory control period. Figure B.2 shows Ausgrid’s indicative proposed forecast capex in each year of the 2014–19 regulatory control period.

For its transmission assets, Ausgrid’s indicative proposed total forecast capex for the 2014–19 period is \$549 million (\$2013–14).¹³⁰ This is \$810 million (\$2013–14), or 59 per cent, lower than its allowed capex for the 2009–14 regulatory control period. It is \$690 million (\$2013–14), or 58 per cent less than Ausgrid’s actual total capex spend over the 2009–14 regulatory control period. Figure B.3 shows Ausgrid’s indicative proposed forecast capex for its transmission assets in each year of the 2014–19 regulatory control period.

Figure B.2 Ausgrid (distribution) proposed and current period capex (\$m, 2013-14)



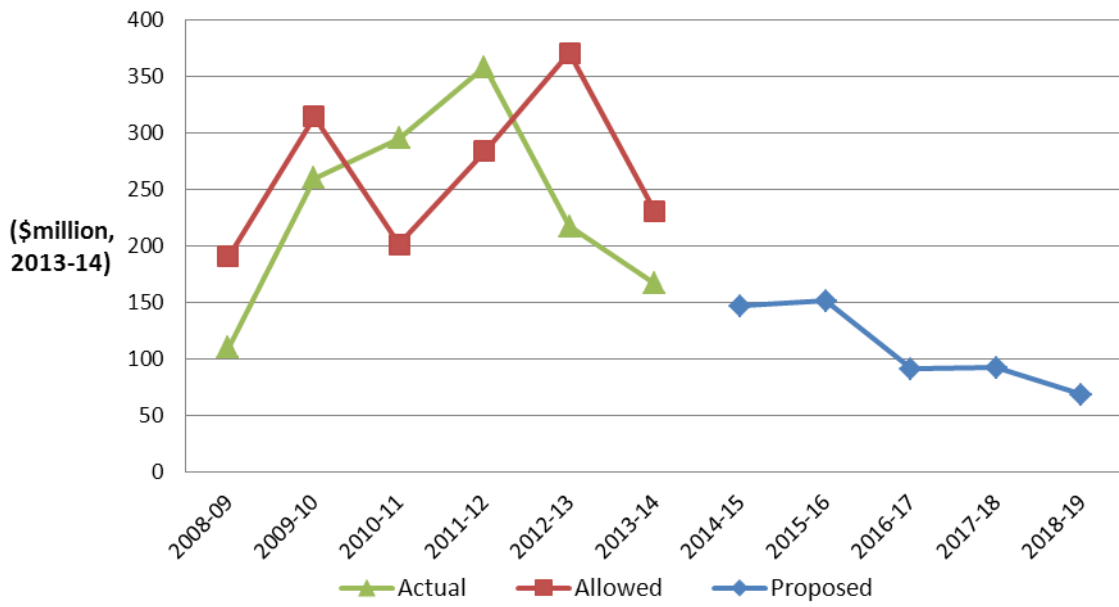
Source: AER analysis.

¹²⁸ Note that the capex amount for the final year of the regulatory control period is an estimate.

¹²⁹ This \$3974 million (real \$2013–14) includes equity raising costs (in 2014–15), metering capex (across 2014–19) and a half year WACC adjustment; and is net of capital contributions and asset disposals.

¹³⁰ This \$549 million (real \$2013–14) includes equity raising costs (in 2014–15) and a half year WACC adjustment; and is net of capital contributions and asset disposals

Figure B.3 Ausgrid (transmission) proposed and current period capex (\$m, 2013-14)



Source: AER analysis.

B.2 Essential Energy

B.2.1 Total revenue

Table B.8 shows Essential Energy's proposed total revenue for each year of the 2014–19 regulatory control period broken down by its constituent building blocks and the proposed revenue smoothing.

Table B.8 Essential Energy's proposed building blocks and total revenue (\$m, nominal)

Building blocks	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Return on capital		579	620	656	692	727
Return of capital		99	118	132	135	129
Operating expenditure		481	479	475	484	497
Efficiency carryover		-15	-53	-48	39	0
Net tax allowance		71	75	79	85	86
Metering and other revenue		71	60	63	69	78
Total revenue (unsmoothed)		1285	1300	1356	1505	1516
Total revenue (smoothed)	1361	1363	1375	1382	1390	1407
Change ^a (%)		0.1%	0.9%	0.5%	0.6%	1.2%

Source: Essential Energy, *Transitional regulatory proposal*, January 2014. Essential Energy, *Post-Tax Revenue Model* January 2014.

Notes: Numbers may not sum due to rounding.

a. This row shows the year-on-year change in total nominal revenues. It should not be interpreted as the X-factor change from year to year.

The key determinants of the building blocks from Essential Energy's proposal (opex, capex, rate of return and RAB) are separately presented below. Essential Energy's proposal also included details on:

- Regulatory depreciation—Essential Energy proposed to use straight-line depreciation as calculated in the PTRM, and put forward a schedule of asset lives. Its depreciation forecasts (including the net effect of indexation) are included in the RAB roll forward table presented below.
- Cost of corporate income tax—Essential Energy submitted taxation calculations using the PTRM, which involves calculating the indicative tax payable and then reducing its tax allowance with respect to the value of imputation credits. Essential Energy's proposed gamma figure (assumed value of imputation credits) is discussed below in the rate of return section.
- Efficiency carryovers—Essential Energy proposed a negative carryover allowance reflecting past efficiency losses associated with its opex (under the EBSS) over the current regulatory control period.
- Metering revenue—Essential Energy has proposed a revenue allowance to recover the costs of providing distribution metering services in its TRP. Metering services will be unbundled from standard control services from 1 July 2014 to alternative control services. However, the transitional rules require Essential Energy to recover the costs of providing these services as part of standard control services for the transitional regulatory control period. For the subsequent regulatory control period metering costs will not be recovered via Essential Energy's standard control services revenue.

B.2.2 Rate of return

Essential Energy proposed an indicative WACC range of 8.5 to 9.1 per cent for the transitional regulatory control period. This indicative WACC range reflects the parameters shown in Table B.3. Essential Energy considered multiple models and estimation methods in estimating the return on equity, before adopting a long-term average approach to arrive at a point estimate.¹³¹ Essential Energy submitted that their approach is consistent with the requirement to have regard to relevant estimation methods, financial models, market data and other evidence when determining the allowed rate of return.¹³² Essential Energy's return on equity estimates are based on a report commissioned in January 2014 by the Competition Economists Group (CEG).¹³³

Essential Energy proposed to adopt a trailing average portfolio approach (with a 10-year debt term and BBB+ credit rating) to estimate the return on debt as set out in our rate of return guideline.¹³⁴ However, they submitted that historical rates would best match their actual debt financing practices (the immediate adoption of a trailing average debt portfolio).¹³⁵

Essential Energy adopted a value of 0.25 for imputation credits (gamma).¹³⁶

B.2.3 RAB

The opening RAB at 1 July 2014 is a key determinant of the allowed revenue for the transitional regulatory control period. It directly influences the return on capital and return of capital building blocks. Table B.9 shows Essential Energy's proposed roll forward of its RAB across the 2009–14 regulatory control period in order to derive the opening RAB.

Table B.9 Derivation of Essential Energy's opening RAB as at 1 July 2014 (\$m, nominal)

RAB	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	4319	4821	5384	6066	6518
Net capital expenditure	688	724	771	655	585
Straight-line depreciation	-266	-298	-272	-309	-334
Inflation adjustment	79	137	182	107	163
Closing RAB	4821	5384	6066	6518	6933
Net adjustments from 2008–09					-45
Opening RAB as at 1 July 2014					6888

Source: Essential Energy, *Roll Forward Model*, January 2014.

Notes: Numbers may not sum due to rounding.

Table B.9 also includes adjustments that relate to 2008–09. When the AER made its determination for the current regulatory control period, final figures for 2008–09 could not be obtained (since the year was not yet complete). Hence, Essential Energy's proposal adjusts for the difference between actual and estimated capex for the 2008–09 financial year.

¹³¹ Ausgrid, *Transitional regulatory proposal*, January 2014, p. 22.

¹³² NER, clause 6.5.2(e)(1).

¹³³ CEG, *WACC estimates*, January 2014.

¹³⁴ AER, *Better regulation rate of return guideline*, December 2013.

¹³⁵ Ausgrid, *Transitional regulatory proposal*, January 2014, p. 21.

¹³⁶ Ausgrid, *Post-tax revenue model*, January 2014.

Table B.10 shows Essential Energy's proposed roll forward of the RAB from 1 July 2014 to 30 June 2019. This roll forward builds on the proposed capex outlined above.

Table B.10 Essential Energy's proposed RAB 2014–19 (\$m, nominal)

RAB	2014–15	2015–16	2016–17	2017–18	2018–19
Opening RAB	6790	7278	7699	8121	8533
Net capital expenditure	587	539	554	548	549
Straight-line depreciation	-269	-300	-325	-338	-342
Inflation adjustment ^a	170	182	192	203	213
Closing RAB	7278	7699	8121	8533	8953

Source: Essential Energy, *Transitional regulatory proposal*, January 2014. Essential Energy, *Post-Tax Revenue Model*, January 2014.

Notes: Numbers may not sum due to rounding.

a. Based on a forecast inflation rate of 2.50 per cent per annum.

B.2.4 Operating expenditure

Essential Energy has used the actual opex of 2012–13 as its base year. To derive forecast opex for 2014–15 to 2018–19 Essential energy has added opex for the following factors:

- forecast changes in labour costs¹³⁷
- loss of synergy from the sale of associated retail service providers¹³⁸
- the impact of reductions capex on opex requirements including the impact of a reduced capex program on its cost structures¹³⁹
- increase in opex due to network growth.¹⁴⁰

Essential Energy has also forecast productivity improvements to offset some of the cost increases identified above.

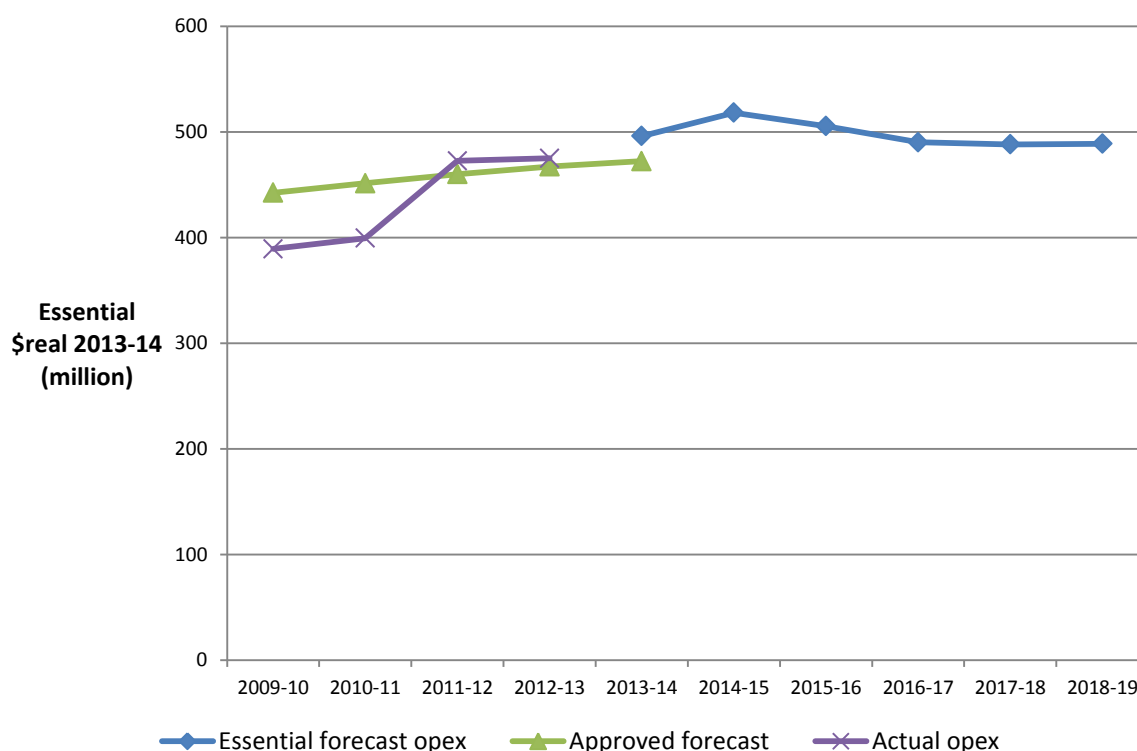
¹³⁷ AusGrid, *Transitional revenue proposal 2014/15*, 31 January 2014, pp. 31-32; Endeavour Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 34; Essential Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 37.

¹³⁸ AusGrid, *Transitional revenue proposal 2014/15*, 31 January 2014, pp. 31-32; Endeavour Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 35; Essential Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 37.

¹³⁹ AusGrid, *Transitional revenue proposal 2014/15*, 31 January 2014, p. 33; Endeavour Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 35; Essential Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 37.

¹⁴⁰ Essential Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 37.

Figure B.4 Comparison of Essential Energy’s forecast opex to its recent actual opex



Source: AER analysis.

B.2.5 Capital expenditure

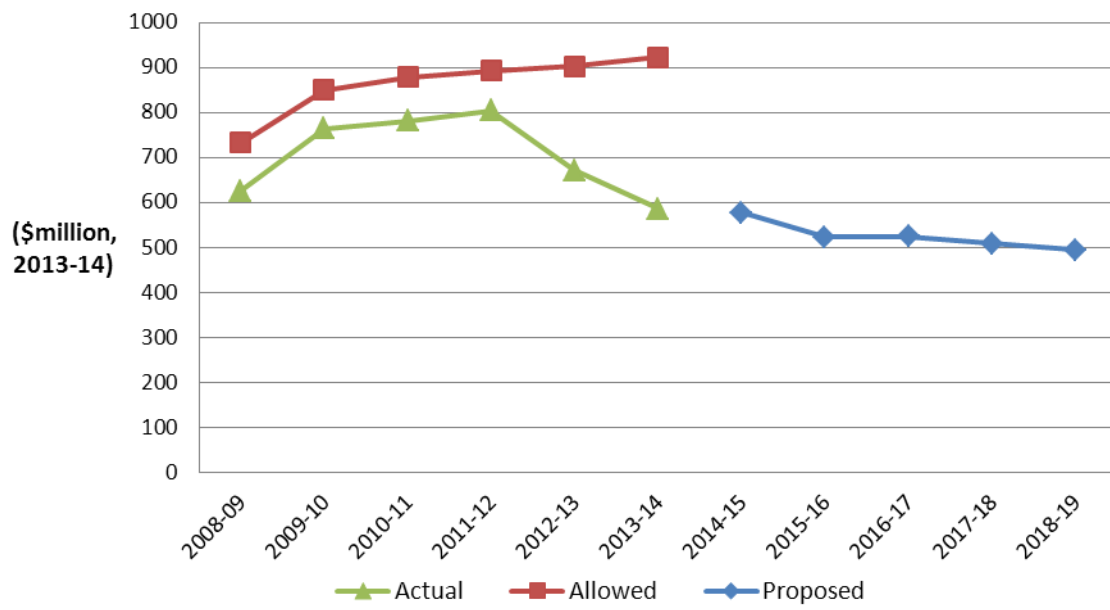
Essential Energy’s actual total capex spend was around 19 per cent less than its forecast capex over the 2009–14 regulatory control period. It spent \$3605 million (\$2013–14) compared with a capex allowance of \$4445 million (\$2013–14). This is an underspend of \$840 million. As shown in Figure B.5, Essential Energy consistently underspent its capex allowance in each year of the regulatory control period with greater underspends occurring in the last 2 years of 25.6 per cent and 36.5 per cent respectively.¹⁴¹

Essential Energy’s indicative proposed total forecast capex for the 2014–19 period is \$2625 million (\$2013–14).¹⁴² This is \$1821 million (\$2013–14), or 41 per cent, lower than its allowed capex for the 2009–14 regulatory control period. It is \$981 million (\$2013–14), or 27 per cent less than Essential Energy’s actual total capex spend over the 2009–14 regulatory control period. Figure B.5 shows Essential Energy’s indicative proposed forecast capex in each year of the 2014–19 period.

¹⁴¹ Note that the capex amount for the final year of the regulatory control period is an estimate.

¹⁴² This \$2625 million (real \$2013–14) includes equity raising costs (in 2014–15), metering capex (across 2014–19) and a half year WACC adjustment; and is net of capital contributions and asset disposals.

Figure B.5 Essential Energy proposed and current period capex (\$m, 2013-14)



Source: AER analysis.

B.3 Endeavour Energy

B.3.1 Total revenue

Table B.11 shows Endeavour Energy's proposed total revenue for each year of the 2014–19 regulatory control period broken down by its constituent building blocks and the proposed revenue smoothing.

Table B.11 Endeavour Energy's proposed building blocks and total revenue (\$m, nominal)

Building blocks	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Return on capital		477	510	536	558	581
Return of capital		63	72	83	88	93
Operating expenditure		292	300	303	305	316
Efficiency carryover		97	33	42	34	0
Net tax allowance		59	62	68	69	71
Metering costs and expected ANS and ERW revenues		63	-	-	-	-
Total revenue (unsmoothed)		1050	978	1032	1053	1061
Total revenue (smoothed)	1015	1007	1007	1031	1053	1085
Change ^a (%)		-0.8%	-0.0%	2.4%	2.1%	3.1%

Source: Endeavour Energy, *Transitional regulatory proposal*, January 2014. Endeavour Energy, *Post-Tax Revenue Model*, January 2014.

Notes: Numbers may not sum due to rounding.

a. This row shows the year-on-year change in total nominal revenues. It should not be interpreted as the X-factor change from year to year.

The key determinants of the building blocks from Endeavour Energy's proposal (opex, capex, rate of return and RAB) are separately presented below. Endeavour Energy's proposal also included details on:

- Regulatory depreciation—Endeavour Energy proposed to use straight-line depreciation as calculated in the PTRM, and put forward a schedule of asset lives. Its depreciation forecasts (including the net effect of indexation) are included in the RAB roll forward table presented below.
- Cost of corporate income tax—Endeavour Energy submitted taxation calculations using the PTRM, which involves calculating the indicative tax payable and then reducing its tax allowance with respect to the value of imputation credits. Endeavour Energy's proposed gamma figure (assumed value of imputation credits) is discussed below in the rate of return section.
- Efficiency carryovers—Endeavour Energy proposed a positive carryover allowance reflecting past efficiency gains associated with its opex (under the EBSS) over the current regulatory control period.
- Metering revenue—Endeavour Energy has proposed a revenue allowance to recover the costs of providing distribution metering services for 2014–15 in its TRP. Metering services will be unbundled from standard control services from 1 July 2014 and treated as alternative control services. However, the transitional rules require Endeavour Energy to recover the costs of providing these services as part of standard control services for the transitional regulatory control

period. Endeavour Energy has not included metering costs for the subsequent regulatory control period as the associated revenue will not be recovered via Endeavour Energy's standard control services revenue.

B.3.2 Rate of return

Endeavour Energy proposed an indicative WACC range of 8.5–9.1 per cent for the 2014–15 regulatory control period. This indicative WACC range reflects the parameters shown in Table B.3.

Endeavour Energy considered multiple models and estimation methods in estimating the return on equity, before adopting a long-term average approach to arrive at a point estimate.¹⁴³ Endeavour Energy submitted that their approach is consistent with the requirement to have regard to relevant estimation methods, financial models, market data and other evidence when determining the allowed rate of return.¹⁴⁴ Endeavour Energy's return on equity estimates are based on a report commissioned in January 2014 by the Competition Economists Group (CEG).¹⁴⁵

Endeavour Energy proposed to adopt a trailing average portfolio approach (with a 10-year debt term and BBB+ credit rating) to estimate the return on debt as set out in our rate of return guideline (guideline).¹⁴⁶ However, they submitted that historical rates would best match their actual debt financing practices (the immediate adoption of a trailing average debt portfolio).¹⁴⁷

Endeavour Energy adopted a value of 0.25 for imputation credits (gamma).¹⁴⁸

B.3.3 RAB

The opening RAB at 1 July 2014 is a key determinant of the allowed revenue for the transitional regulatory control period. It directly influences the return on capital and return of capital building blocks. Table B.12 shows Endeavour Energy's proposed roll forward of its RAB across the 2009–14 regulatory control period in order to derive the opening RAB.

Table B.12 Derivation of Endeavour Energy's opening RAB as at 1 July 2014 (\$m, nominal)

RAB	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	3690	3940	4340	4908	5344
Net capital expenditure	423	507	647	582	564
Straight-line depreciation	-240	-220	-227	-232	-231
Inflation adjustment	67	112	147	87	132
Closing RAB	3940	4340	4908	5344	5809
Net adjustments from 2008–09					-193
Opening RAB as at 1 July 2014					5616

Source: Endeavour Energy, *Transitional regulatory proposal*, p. 17.

Notes: Numbers may not sum due to rounding.

¹⁴³ Ausgrid, *Transitional regulatory proposal*, January 2014, p. 22.

¹⁴⁴ NER, clause 6.5.2(e)(1).

¹⁴⁵ CEG, *WACC estimates*, January 2014.

¹⁴⁶ AER, *Better regulation rate of return guideline*, December 2013.

¹⁴⁷ Ausgrid, *Transitional regulatory proposal*, January 2014, p. 21.

¹⁴⁸ Ausgrid, *Post-tax revenue model*, January 2014.

Table B.12 also includes adjustments that relate to 2008–09. When the AER made its determination for the current regulatory control period, final figures for 2008–09 could not be obtained (since the year was not yet complete). Hence, Endeavour Energy’s proposal adjusts for the difference between actual and estimated capex for the 2008–09 financial year.

Table B.13 shows Endeavour Energy’s proposed roll forward of the RAB from 1 July 2014 to 30 June 2019. This roll forward builds on the proposed capex outlined above.

Table B.13 Endeavour Energy's proposed RAB 2014–19 (\$m, nominal)

RAB	2014–15	2015–16	2016–17	2017–18	2018–19
Opening RAB	5593	5983	6289	6544	6813
Net capital expenditure	452	379	338	357	348
Straight-line depreciation	-202	-222	-240	-252	-264
Inflation adjustment ^a	140	150	157	164	170
Closing RAB	5983	6289	6544	6813	7067

Source: Endeavour Energy, *Transitional regulatory proposal*, January 2014. Endeavour Energy, *Post-Tax Revenue Model*, January 2014.

Notes: Numbers may not sum due to rounding.

a. Based on a forecast inflation rate of 2.50 per cent per annum.

B.3.4 Operating expenditure

Endeavour Energy has used the actual opex of 2012–13 as its base year. To derive forecast opex for 2014-15 to 2018-19 Endeavour Energy has added opex for the following factors:

- Forecast changes in labour costs¹⁴⁹
- Loss of synergy from the sale of associated retail service providers¹⁵⁰
- The impact of reductions capex on opex requirements including the impact of a reduced capex program on its cost structures¹⁵¹
- An increase in vegetation management costs due to observed improvements in contract performance from its market providers.¹⁵²

Endeavour Energy has also forecast productivity improvements to offset some of the cost increases identified above.

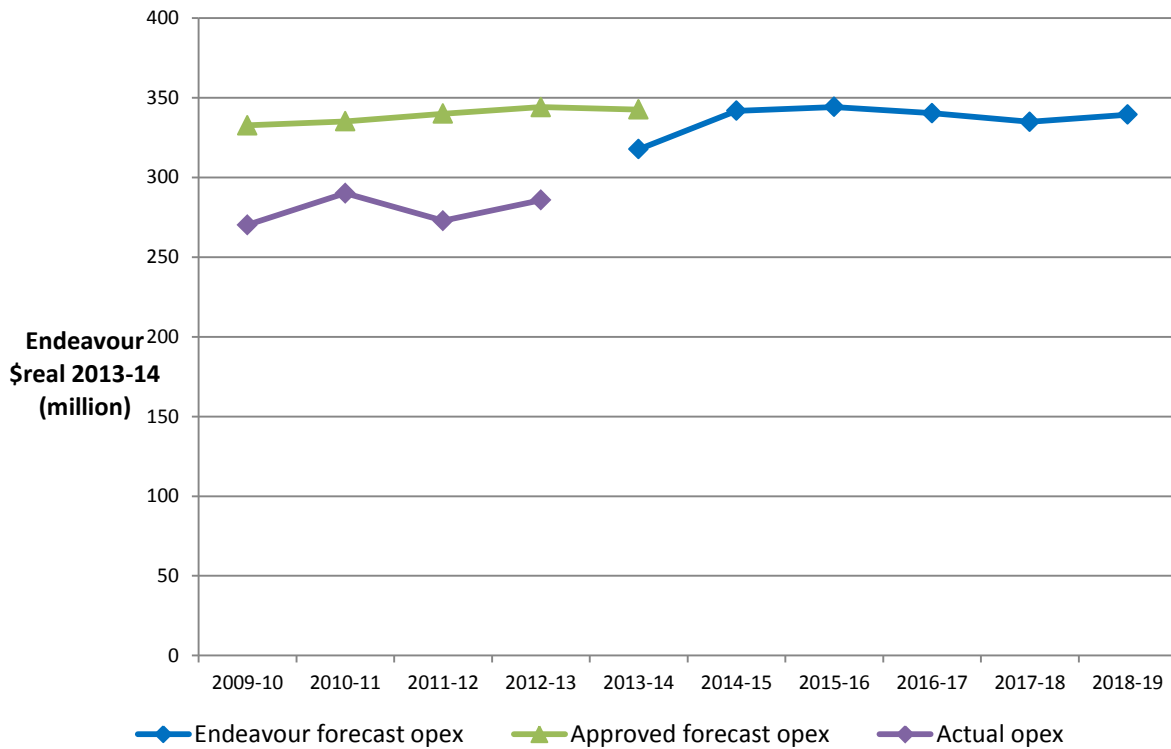
¹⁴⁹ Ausgrid, *Transitional revenue proposal 2014/15*, 31 January 2014, pp. 31-32; Endeavour Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 34; Essential Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 37.

¹⁵⁰ Ausgrid, *Transitional revenue proposal 2014/15*, 31 January 2014, pp. 31-32; Endeavour Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 35; Essential Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 37.

¹⁵¹ Ausgrid, *Transitional revenue proposal 2014/15*, 31 January 2014, p. 33; Endeavour Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 35; Essential Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 37.

¹⁵² Endeavour Energy, *Transitional revenue proposal*, 2014/15, 31 January 2014, p. 34.

Figure B.6 Comparison of Endeavour Energy’s forecast opex to its recent actual opex



Source: AER analysis.

B.3.5 Capital expenditure

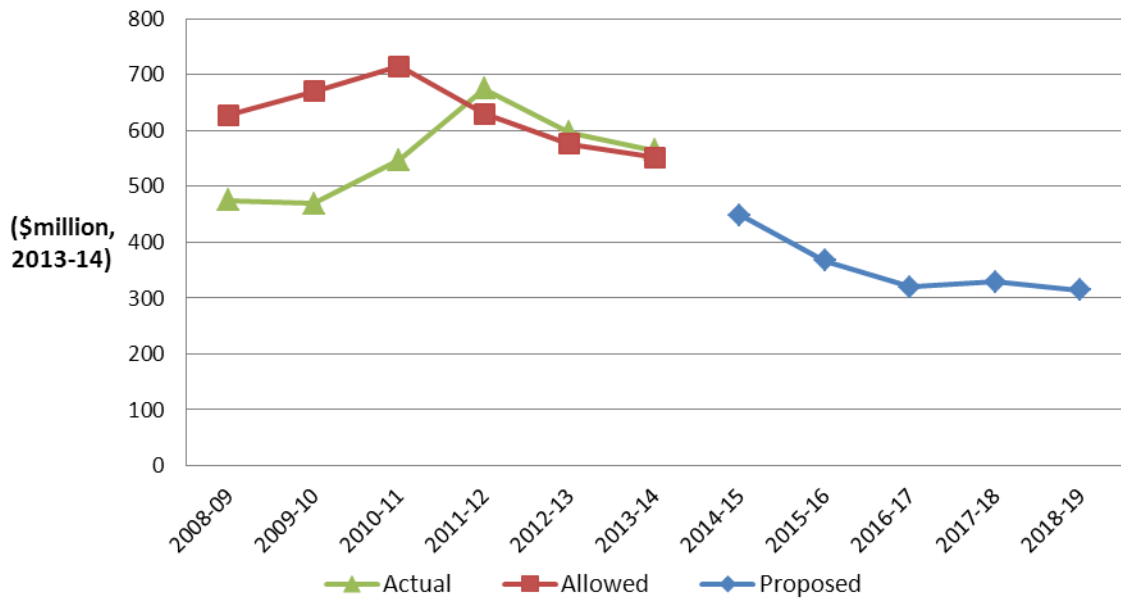
Endeavour Energy’s actual total capex spend was around 9 per cent less than its forecast capex over the 2009–14 regulatory control period. It spent \$2852 million (\$2013–14) compared with a capex allowance of \$3143 million (\$2013–14). This is an underspend of \$291 million. As shown in Figure B.7, the majority of this underspend was in the first 2 years of the regulatory control period where Endeavour Energy underspend by 30 per cent and 24 per cent respectively. Since 2011–12, Endeavour Energy has marginally overspent its capex allowance.¹⁵³

Endeavour Energy’s indicative proposed total forecast capex for the 2014–19 period is \$1776 million (\$2013–14).¹⁵⁴ This is \$1367 million (\$2013–14), or 44 per cent, lower than its allowed capex for the 2009–14 regulatory control period. It is \$1076 million (\$2013–14), or 38 per cent less than Endeavour Energy’s actual total capex spend over the 2009–14 regulatory control period. Figure B.7 shows Endeavour Energy’s indicative proposed forecast capex in each year of the 2014–19 regulatory control period.

¹⁵³ Note that the capex amount for the final year of the regulatory control period is an estimate.

¹⁵⁴ This \$1776 million (real \$2013–14) includes equity raising costs (in 2014–15), metering capex (across 2014–19) and a half year WACC adjustment; and is net of capital contributions and asset disposals.

Figure B.7 Endeavour Energy proposed and current period capex (\$m, 2013-14)



Source: AER analysis.

B.4 ActewAGL

B.4.1 Total revenue

Table B.14 and Table B.15 show ActewAGL's proposed total revenue for each year of the 2014–19 regulatory control period for its distribution and transmission networks respectively. The total revenue is broken up by its constituent building blocks and shows ActewAGL's proposed revenue smoothing. In the current regulatory control period, the entire ActewAGL network (distribution and transmission) was regulated as one entity. To calculate the 2013–14 revenue shown in these tables, it is necessary to notionally allocate the revenue between the distribution and transmission networks.¹⁵⁵

Table B.14 ActewAGL's proposed building blocks and total revenue – distribution (\$m, nominal)

Building blocks	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Return on capital		62	66	69	72	75
Return of capital		28	31	31	33	33
Operating expenditure		65	65	63	64	69
Efficiency carryover		-13	-10	-2	-2	0
Net tax allowance		10	11	10	12	12
Total revenue (unsmoothed)		151	164	172	179	189
Total revenue (smoothed)	152^a	156	162	170	179	187
Change ^b (%)		2.3%	3.7%	5.2%	5.1%	4.5%

Source: ActewAGL, *Transitional regulatory proposal*, January 2014, p. 23; AER calculations.

Notes: Numbers may not sum due to rounding.

a. This figure has been adjusted to reflect only the (notional) distribution component of 2013–14 revenue.

b. This row shows the year-on-year change in total nominal revenues. It should not be interpreted as the X-factor change from year to year.

¹⁵⁵ The AER approach to this allocation differs from that taken by ActewAGL. In ActewAGL's PTRMs, a portion of the 2013–14 revenue was assigned to the transmission network so that an indicative change from 2013–14 to 2014–15 could be calculated. However, ActewAGL did not deduct this revenue from the equivalent calculation for the distribution network, effectively double counting this revenue.

Table B.15 ActewAGL's proposed building blocks and total revenue – transmission (\$m, nominal)

Building blocks	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Return on capital		14	14	15	18	19
Return of capital		4	5	5	6	6
Operating expenditure		13	13	13	13	14
Efficiency carryover		-2	-1	0	0	0
Net tax allowance		1	2	2	2	2
Total revenue (unsmoothed)		30	32	34	38	41
Total revenue (smoothed)	28^a	30	33	35	38	41
Change ^b (%)		7.8%	7.8%	7.8%	7.8%	7.8%

Source: ActewAGL, *Transitional regulatory proposal*, January 2014, p. 23; AER calculations.

Notes: Numbers may not sum due to rounding.

a. This figure has been adjusted to reflect the (notional) transmission component of 2013–14 revenue.

b. This row shows the year-on-year change in total nominal revenues. It should not be interpreted as the X-factor change from year to year.

The key determinants of the building blocks from ActewAGL's proposal (opex, capex, rate of return and RAB) are separately presented below. ActewAGL's proposal also included details on:

- Regulatory depreciation—ActewAGL proposed to use straight-line depreciation as calculated in the PTRM, and put forward a schedule of asset lives. Its depreciation forecasts (including the net effect of indexation) are included in the RAB roll forward tables presented below.
- Cost of corporate income tax—ActewAGL submitted taxation calculations using the PTRM, which involves calculating the indicative tax payable and then reducing its tax allowance with respect to the value of imputation credits. ActewAGL's proposed gamma figure (assumed value of imputation credits) is discussed below in the rate of return section.
- Efficiency carryovers—ActewAGL proposed a negative carryover allowance for both its distribution and transmission networks. This reflects past efficiency losses associated with its opex (under the EBSS) over the current regulatory control period.

B.4.2 Rate of return

ActewAGL proposed an indicative WACC range of 8.8 to 9.5 per cent for the transitional regulatory control period.¹⁵⁶ This indicative WACC range reflects the parameters shown in Table B.16.

ActewAGL adopted a similar approach to the NSW DNSPs in estimating the return on equity. It considered multiple models and estimation methods before adopting the Wright approach to arrive at a point estimate.¹⁵⁷ ActewAGL submitted that their approach is consistent with the requirement to have regard to relevant estimation methods, financial models, market data and other evidence when

¹⁵⁶ ActewAGL, *Transitional regulatory proposal*, January 2014, p. 35.

¹⁵⁷ ActewAGL, *Transitional regulatory proposal*, January 2014, pp. 32–33.

determining the allowed rate of return.¹⁵⁸ ActewAGL's return on equity estimates draw on material presented during the guideline consultation process by the ENA.¹⁵⁹

ActewAGL adopted a similar approach to the NSW DNSPs in estimating the return on debt. It submitted that historical rates would best match their actual debt financing practices (the immediate adoption of a trailing average debt portfolio).¹⁶⁰

ActewAGL adopted a value of 0.25 for imputation credits (gamma) calculated as the product of the payout ratio (0.7) and utilisation rate (0.35).¹⁶¹ It submitted that this value is consistent with the approach taken in the Australian Competition Tribunal's decision in 2011 and IPART's Review of WACC methodology.¹⁶²

Table B.16 ActewAGL's proposed WACC parameters for the transitional regulatory control period

	ActewAGL
Risk free rate	4.3
Market risk premium	6.5–7.2 (7.3)
Equity beta	0.79–0.82 (0.82)
Cost of equity	10.0–11.8 (10.3)
Debt risk premium	3.7
Cost of debt	8.0
Gamma	0.25
Nominal vanilla WACC	8.8–9.5 (8.9)

Source: Ausgrid, *Transitional revenue proposal*, January 2014. ActewAGL, *Transitional revenue proposal*, January 2014. Ausgrid, *Post-tax revenue model*, January 2014. ActewAGL, *Post-tax revenue model*, January 2014.

Note: Where the service provider submitted a range for a parameter, the table includes the range and the final proposed value (in parentheses).

B.4.3 RAB

The opening RAB at 1 July 2014 is a key determinant of the allowed revenue for the transitional regulatory control period. It directly influences the return on capital and return of capital building blocks. In the current regulatory control period, the entire ActewAGL network (distribution and transmission) was regulated as one entity. To calculate the RABs shown in the tables below, ActewAGL has divided the opening RAB at 1 July 2009 between the distribution and transmission networks with regard to the underlying assets. ActewAGL also allocated capex across the current regulatory control period between the distribution and transmission networks using a consistent cost allocation methodology.¹⁶³ Table B.17 and Table B.18 show ActewAGL's proposed roll forward of its distribution and transmission RABs respectively across the 2009–14 regulatory control period in order to derive the opening RABs.

¹⁵⁸ NER, clause 6.5.2(e)(1).

¹⁵⁹ ENA, *Response to the draft rate of return guideline of the Australian Energy Regulator*, October 2013.

¹⁶⁰ ActewAGL, *Transitional regulatory proposal*, January 2014, pp. 34–35.

¹⁶¹ ActewAGL, *Transitional regulatory proposal*, January 2014, p. 35.

¹⁶² Australian Competition Tribunal, *Application by Energex Limited (gamma) (No 5) [2011] ACompT9*, May 2011. IPART, *Review of WACC methodology*, December 2013.

¹⁶³ ActewAGL, *Transitional regulatory proposal*, January 2014, pp. 12–15.

Table B.17 Derivation of ActewAGL's opening RAB as at 1 July 2014 - distribution (\$m, nominal)

RAB	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	523	560	604	641	662
Net capital expenditure	54	57	49	45	70
Straight-line depreciation	-27	-29	-32	-35	-38
Inflation adjustment	10	16	20	11	16
Closing RAB	560	604	641	662	710
Net adjustments from 2008–09					-10
Opening RAB as at 1 July 2014					701

Source: ActewAGL, *Transitional regulatory proposal*, January 2014, p. 14.

Notes: Numbers may not sum due to rounding.

Table B.18 Derivation of ActewAGL's opening RAB as at 1 July 2014 – transmission (\$m, nominal)

RAB	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	75	86	99	117	136
Net capital expenditure	13	15	20	23	20
Straight-line depreciation	-4	-4	-5	-6	-7
Inflation adjustment	1	2	3	2	3
Closing RAB	86	99	117	136	153
Net adjustments from 2008–09					1
Opening RAB as at 1 July 2014					154

Source: ActewAGL, *Transitional regulatory proposal*, January 2014, p. 14.

Notes: Numbers may not sum due to rounding.

Table B.17 and Table B.18 also include adjustments that relate to 2008–09. When the AER made its determination for the current regulatory control period, final figures for 2008–09 could not be obtained (since the year was not yet complete). Hence, ActewAGL's proposal adjusts for the difference between actual and estimated capex for the 2008–09 financial year.

Table B.19 and Table B.20 show ActewAGL's proposed roll forward of the RABs from 1 July 2014 to 30 June 2019 for its distribution and transmission networks respectively. This builds on the proposed capex outlined above.

Table B.19 ActewAGL's proposed RAB 2014–19 – distribution (\$m, nominal)

RAB	2014–15	2015–16	2016–17	2017–18	2018–19
Opening RAB	701	746	778	812	844
Net capital expenditure	72	63	66	65	69
Straight-line depreciation	-44	-47	-47	-48	-48
Inflation adjustment ^a	17	18	19	20	21
Closing RAB	746	778	812	844	881

Source: ActewAGL, *Transitional regulatory proposal*, January 2014, p. 14.

Notes: Numbers may not sum due to rounding.

a. Based on a forecast inflation rate of 2.45 per cent per annum.

Table B.20 ActewAGL's proposed RAB 2014–19 – transmission (\$m, nominal)

RAB	2014–15	2015–16	2016–17	2017–18	2018–19
Opening RAB	154	160	169	197	215
Net capital expenditure	10	15	33	23	13
Straight-line depreciation	-8	-9	-9	-11	-11
Inflation adjustment ^a	4	4	4	5	5
Closing RAB	160	169	197	215	221

Source: ActewAGL, *Transitional regulatory proposal*, January 2014, p. 14.

Notes: Numbers may not sum due to rounding.

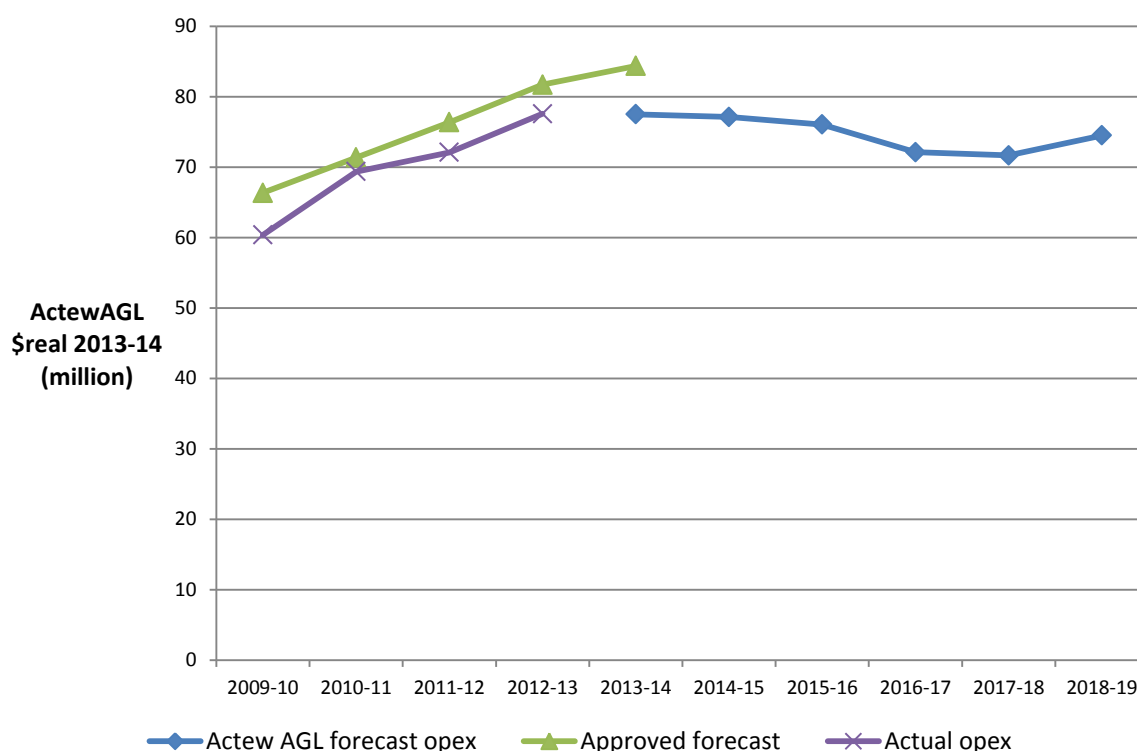
a. Based on a forecast inflation rate of 2.45 per cent per annum.

B.4.4 Operating expenditure

ActewAGL has used a mixture of zero based and base year approaches to forecast its opex. Some of the cost increases ActewAGL has forecast include new regulatory reporting and environmental health safety and quality costs. Forecast cost decreases include a reduced intake of new apprenticeships as a result of a recent review of ActewAGL's program of work, employee turnover and future work requirements.¹⁶⁴

¹⁶⁴ ActewAGL *Transitional revenue proposal 2014/15*, 31 January 2014, pp. B-12-B-15.;

Figure B.8 Comparison of ActewAGL’s forecast opex to its recent actual opex



Source: ActewAGL, *Transitional regulatory proposal*, January 2014, p. 23; AER calculations.

Capital expenditure

The information below relates to ActewAGL’s whole of business (distribution and transmission) capex.

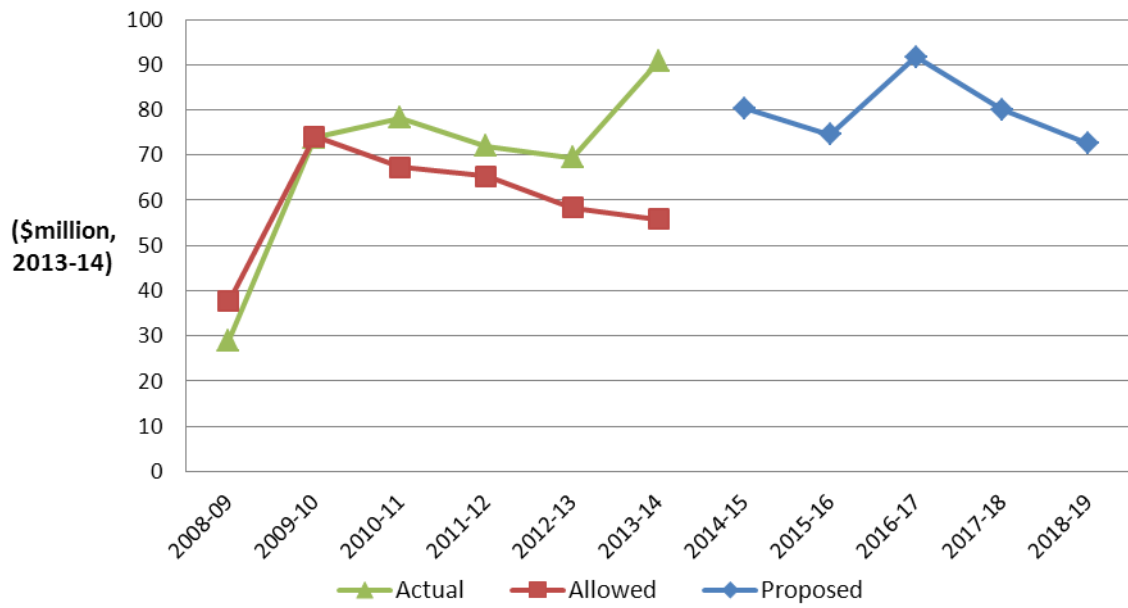
ActewAGL’s actual total capex spend was around 20 per cent higher than its forecast capex over the 2009–14 regulatory control period. It spent \$384 million (\$2013–14) compared with a capex allowance of \$321 million (\$2013–14). This is an overspend of \$63 million. As shown in Figure B.9 ActewAGL overspent its capex allowance by more than 10 per cent in every year except the first year of the regulatory control period.¹⁶⁵

ActewAGL’s indicative proposed total forecast capex for the 2014–19 period is \$400 million (\$2013–14).¹⁶⁶ This is \$79 million (\$2013–14), or 25 per cent, higher than its allowed capex for the 2009–14 regulatory control period. It is \$16 million (\$2013–14), or 4 per cent more than ActewAGL’s actual total capex spend over the 2009–14 regulatory control period. Figure B.9 shows ActewAGL’s indicative proposed forecast capex in each year of the 2014–19 period.

¹⁶⁵ Note that the capex amount for the final year of the regulatory control period is an estimate.

¹⁶⁶ This \$400 million (real \$2013–14) includes equity raising costs (in 2014-15) and a half year WACC adjustment; is net of capital contributions and asset disposals; and excludes metering capex.

Figure B.9 ActewAGL (whole of business) proposed and current period capex (\$m, nominal)



Source: AER analysis.