FINAL DECISION ActewAGL distribution determination 2015−16 to 2018−19

Overview

April 2015

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Note

This overview forms part of the AER's final decision on ActewAGL's distribution determination for 2015–19. It should be read with other parts of the final decision.

The final decision includes the following documents:

Overview

Attachment 1 – annual revenue requirement

Attachment 2 – regulatory asset base

Attachment 3 – rate of return

Attachment 4 – value of imputation credits

Attachment 5 – regulatory depreciation

Attachment 6 – capital expenditure

Attachment 7 – operating expenditure

Attachment 8 – corporate income tax

Attachment 9 – efficiency benefit sharing scheme

Attachment 10 – capital expenditure sharing scheme

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Attachment 12 – demand management incentive scheme

Attachment 13 – classification of services

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Attachment 17 – negotiated services framework and criteria

Attachment 18 – connection policy

Attachment 19 – pricing methodology

Attachment 20 – analysis of financial viability

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Shortened forms

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

Shortened form	Extended form
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

1 Our final decision

The Australian Energy Regulator (AER) is responsible for the economic regulation of electricity transmission and distribution systems in all states and territories except Western Australia and the Northern Territory. ActewAGL is the distribution network service provider in the ACT.[1] We regulate the revenues ActewAGL can recover from its customers.

The National Electricity Law (NEL) and National Electricity Rules (NER) provide the regulatory framework under which we operate. Most relevantly, they set out how we must assess a regulatory proposal and make our decision.

The National Electricity Objective (NEO) sits at the centre of the NEL and NER. The NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—

> price, quality, safety, reliability and security of supply of electricity; and
>
> the reliability, safety and security of the national electricity system.[2]

Under the NER, ActewAGL must submit a regulatory proposal to us for approval.[3] The central component of a regulatory proposal is the amount of revenue ActewAGL proposes to recover from consumers over the 2015–19 regulatory control period.[4] We must assess ActewAGL's proposal, using the NER's detailed rules. The NER addresses a range of constituent components of a regulatory proposal. We must decide whether to accept ActewAGL's proposal. If we do not accept that ActewAGL's proposal complies with the NER's requirements, we must substitute an alternative amount of revenue that we are satisfied does comply. We must undertake this assessment and make this decision in a manner that will or is likely to contribute to the achievement of the NEO and, where appropriate, contribute to the greatest degree.

We regulate ActewAGL's revenue, not its costs. ActewAGL must then decide how best to use this revenue in providing distribution services and fulfilling its obligations. This provides incentives for distributors, such as ActewAGL, to operate their businesses efficiently and, in the long run, at least cost to consumers. It also provides incentives for distributors to innovate and invest in response to changes in consumer needs and

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1 ActewAGL also has some transmission assets.

2 NEL, s. 7.

3 NER, cl. 6.8.2.

4 NER, cll. 6.3.1 and 6.8.2. As we explained in our draft decision, the regulatory control period is 2015–19. However, the NER requires us to determine a notional annual revenue requirement for each year of the 2014–19 period. We must then true this us with the placeholder 2014–15 annual revenue requirement we determined in the placeholder decision we made in 2014. As a result, this decision often refers to the 2014–19 period, rather than the 2015–19 regulatory control period.

productive opportunities.[5] This is consistent with economic efficiency principles. It also means that the person who is best able to manage a risk, generally carries that risk.

ActewAGL submitted a regulatory proposal in May 2014. The AER found this proposal to be non-compliant with the NER.[6] This was because ActewAGL did not nominate averaging periods to determine its return on debt, as set out in the Rate of Return Guideline and did not set out its reasons for departing from the Guideline.[7] ActewAGL resubmitted its regulatory proposal[8] which we found to be compliant.[9] In November 2014 we made a draft decision and, in January 2015, ActewAGL submitted a revised proposal. We also received submissions from various stakeholders on ActewAGL's initial and revised proposals as well as our draft decision.

This overview, together with its attachments, constitutes our final decision on ActewAGL's revised proposal. This overview provides a summary of our decision, including all the constituent components that make up our final decision. It sets out the issues we covered, the conclusions we made, and how those conclusions were reached. We also explain why we are satisfied our decision contributes to the achievement of the NEO to the greatest degree and why we do not consider that ActewAGL's revised proposal contributes to the achievement of the NEO to a satisfactory degree. In our attachments we set out detailed analysis of the constituent components that make up ActewAGL's revised proposal and our decision on each of them. There is a full list of the constituent components of this decision in appendix A.

1.1 Decision

Our final decision is that ActewAGL can recover $590.9 million ($ nominal) from consumers over the 2015–19 regulatory control period. Figure 1 illustrates our overall decision.

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

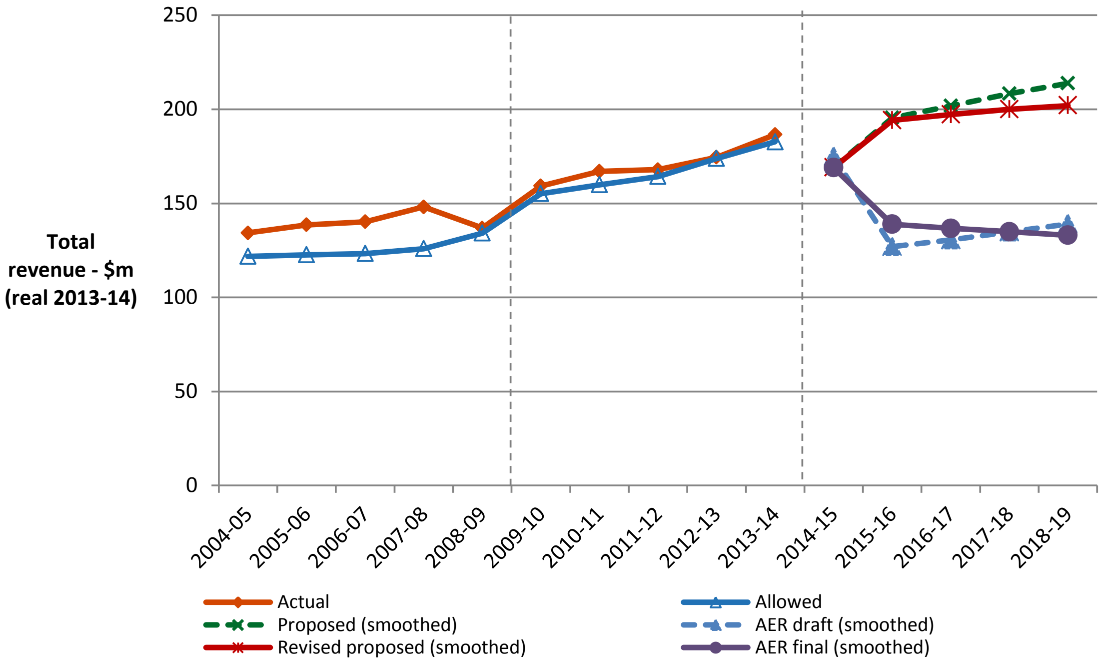
6 The AER issued ActewAGL with a non-compliance notice under clause 6.9.1(a) of the NER, to resubmit its regulatory proposal.

7 NER, cl. S6.1.3(9).

8 Clause 6.9.2 of the NER requires ActewAGL to resubmit its regulatory proposal within 20 business days of receiving the notice.

9 ActewAGL satisfied the notice by setting out methodology to determine the debt averaging periods and identifying and providing reasons for departing from the guidelines.

Figure 1 ActewAGL's past total revenue, proposed total revenue and AER total revenue allowance – distribution and transmission ($ million, 2013–14)



Source: AER analysis.

Distribution charges represent approximately 35 per cent, on average, of the annual electricity bill for ActewAGL customers.[10] If the lower distribution charges flowing from our decision are passed through to customers, we would expect the average annual electricity bill for residential and small business customers to reduce in the 2015–19 regulatory control period. However, other factors may also affect a customer's electricity bill, such as the wholesale price of energy.

Table 1 shows the estimated impact of our final decision on the average residential and small business customers' annual electricity bills in ActewAGL's network area over the 2014–19 period, compared with what was proposed.

10 ActewAGL, *Regulatory proposal*, July 2014, Attachment A3.

Table 1 AER's estimated impact of the final decision on the average residential and small business customers' electricity bills in ActewAGL's network for the 2014–19 period ($ nominal)

	2013–14	2014–15[c]	2015–16	2016–17	2017–18	2018–19
ActewAGL revised proposal						
Residential annual bill[a]	1959	1934	2029	2048	2067	2087
Annual change		–25 (–1.3%)	95 (4.9%)	19 (0.9%)	19 (1.0%)	20 (1.0%)
Small business annual bill[b]	2939	2901	3044	3072	3102	3131
Annual change		–38 (–1.3%)	143 (4.9%)	29 (0.9%)	29 (1.0%)	30 (1.0%)
AER final decision						
Residential annual bill[a]	1959	1934	1822	1818	1817	1819
Annual change		–25 (–1.3%)	–112 (–5.8%)	–4 (–0.2%)	–1 (–0.1%)	2 (0.1%)
Small business annual bill[b]	2939	2901	2733	2728	2726	2729
Annual change		–38 (–1.3%)	–168 (–5.8%)	–6 (–0.2%)	–1 (–0.1%)	3 (0.1%)

Source: AER analysis; ICRC, *Final report-Standing offer electricity prices from 1 July 2014*, pp. 60–61.

(a) For a typical consumption of 8000 kWh per year during the period 1 July 2013 to 30 June 2014.

(b) For a typical consumption of 10000 kWh per year during the period 1 July 2013 to 30 June 2014.

(c) ActewAGL incorporated the 2014–15 numbers from our January 2014 Transitional Revenue Decision into its revised proposal.

1.2 Contribution to the achievement of the NEO

We are satisfied that the total revenue approved in our final decision contributes to the achievement of the NEO to the greatest degree. This is because our total revenue reflects the efficient, sustainable costs of providing network services in ActewAGL's operating environment and the key drivers of efficient costs facing ActewAGL. For the reasons set out below and in our attachments, we consider our decision will promote the efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers, as required by the NEO.

The key drivers of costs facing a network service provider are:[11]

- its accumulated network investment (reflected in the size of its Regulatory Asset Base, or RAB)
- its expected growth in network investment (reflected in its capital expenditure (capex) program net of capital returned to the shareholders through depreciation)

11 How these key cost drivers impact total revenue is further explained in section 2 of this Overview.

- its financing costs (interest on borrowings and a return on equity to shareholders) and
- its operating expenditure (opex) program (the cost of operating and maintaining its network).
- its taxation cost (taxable income at the corporate tax rate adjusted for the value of imputation credits).

From one regulatory period to the next, the pressures on each of these drivers may change. For example, in periods of high demand growth, a network service provider would expect to need a larger capex program. Similarly, during periods of high interest rates, a network service provider would expect to pay more in financing costs.

The most important factors we see impacting on ActewAGL's costs in the 2015–19 period include:

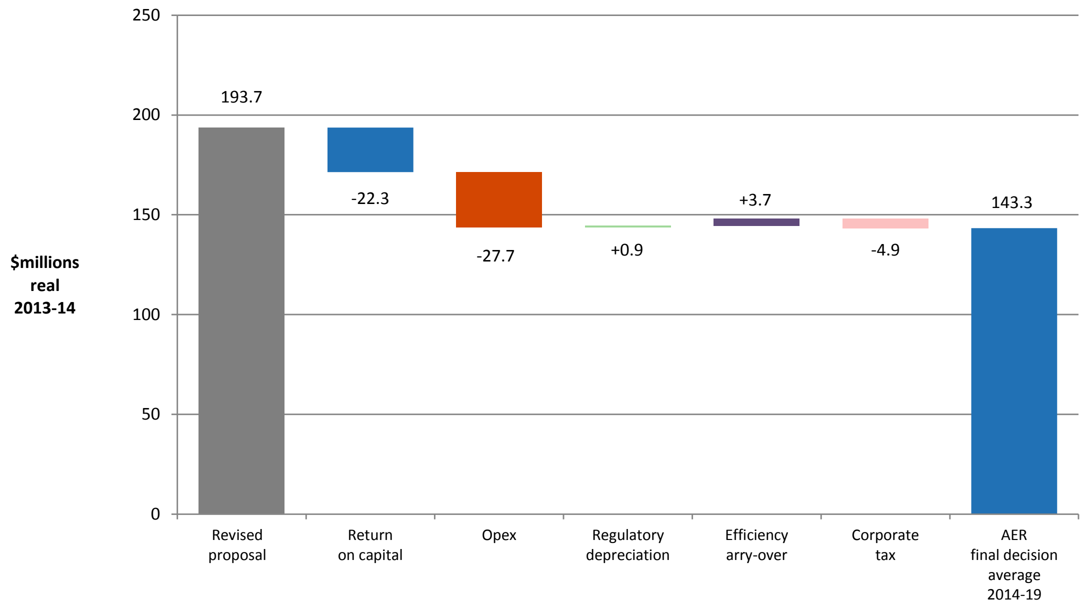
- an improved investment environment compared to our 2009 decision, which translates to lower financing costs necessary to attract efficient investment.
- a consistent body of evidence demonstrating that ActewAGL's past expenditure has been higher than necessary to maintain its network safely and reliably. This evidence has been confirmed by our own opex and capex analysis, including our benchmarking analysis.
- forecast demand, which is expected to remain reasonably flat over the 2015–19 regulatory control period. This means that ActewAGL is under less pressure to expand its network than in the previous regulatory control period to meet the needs of additional customers or any increased demand from existing customers
- the efficiency of ActewAGL's labour and workforce practices. Our review indicates that ActewAGL's historical costs are above levels that a prudent and efficient operator would incur in delivering safe and reliable network services to its customers. This view was supported by our consultant, which found systemic issues in ActewAGL's work practices.As a result, the costs derived from these historical practices are not a reliable base on which to forecast prudent and efficient costs.

These factors are reflected throughout our final decision and impact the different constituent components of our decision to varying degrees. At the total revenue level, they provide a consistent picture: ActewAGL, operating prudently and efficiently, could provide distribution services with materially less revenue than it has proposed for the 2015–19 regulatory control period. Further, the average annual revenue ActewAGL requires in the 2015–19 regulatory control period is materially less than the revenue it recovered from customers in 2013–14.

In our final decision we consider that ActewAGL's proposal does not reflect the factors impacting on its cost drivers to a satisfactory extent. As a consequence, we also consider that ActewAGL has proposed to recover more revenue from its customers than is necessary for the safe and reliable operation of its network. It follows that we consider that ActewAGL's revised proposal does not contribute to the achievement of the NEO to a satisfactory degree.

Two constituent components of our decision drive most of the difference between ActewAGL's proposed revenue and our final decision: rate of return and opex. We discuss these further below. Figure 2 illustrates the key differences (in terms of constituent components, or building blocks, making up total revenue) between our decision and ActewAGL's proposed revenue.

Figure 2 AER's final decision and ActewAGL's proposed annual building block costs – distribution and transmission ($ million 2013–14)



Source: AER analysis.

1.2.1 Rate of return

The rate of return provides a service provider with revenue to service the interest on its borrowings and to give a return on equity to shareholders. The allowed rate of return is a key determinant of allowed revenue.

The rate of return must be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the distributor in respect of the provision of distribution services.[12] The NER refers to this requirement as the allowed rate of return objective.

Our final decision is for a rate of return of 6.48 per cent (2014–15) compared to 8.99 per cent put forward by ActewAGL in its revised proposal.[13] The rate of return for

12 NER, cl. 6.5.2(b).

13 The rate of return that ActewAGL included in its proposal is an indicative value. Its proposal includes provision for the AER to adjust this value based on updated information that was not available when ActewAGL submitted its revised proposal.

2015–16 will be 6.38 per cent. For the rest of the regulatory control period, we will update the rate of return annually.

We set out our approach to determining the rate of return in the Rate of Return Guideline (Guideline) we published in December 2013. This Guideline is not binding. However, a distributor must provide reasons to justify any departure from the Guideline. ActewAGL has proposed we depart from the Guideline. We disagree.

Prevailing market conditions for debt and equity heavily influence the rate of return. In our draft decision we pointed out that financial conditions have improved markedly since our 2009 final decision, resulting in a lower rate of return. Since our draft decision, interest rates have fallen further and financial market conditions have continued to ease. This means that the cost of debt and the returns required to attract equity are lower than when we made our draft decision. We consider these factors should be reflected in the final rate of return.

On a more technical level, there are two key differences between our final decision and ActewAGL's revised proposal in relation to rate of return:

- whether to use a forwards or backwards looking approach in transitioning between approaches to setting our estimate of the return on debt
- whether to give weight to other indicators of the return on equity that ActewAGL consider to be informative but which we do not consider to be robust and which other regulators do not use.

The Guideline, (and indeed, this decision) marks a departure from our previous approach to estimating the return on debt and the return on equity. For the return on debt, we have used a gradual, forward looking transition to do so. We set out this transition in the Guideline. Our approach to setting the return on debt received broad support across many stakeholders, including service providers.[14] The evidence ActewAGL provided does not convince us that we should depart from the approach in our Guideline, for this final decision.[15] For the return on equity, the expert evidence before us indicates that on balance employing our approach is expected to lead to a rate of return that achieves the allowed rate of return objective.

1.2.2 Operating Expenditure

Opex is required to operate and maintain the distributor's network. Like rate of return, it is a key driver of total revenue. Whether we should use ActewAGL's historical costs as the starting point for forecasting its future costs is the key difference between our final decision and ActewAGL's revised proposal. We also did not accept all of ActewAGL's proposed step changes.

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[14] For example, TasNetworks, *Regulatory Proposal*, June 2014.

[15] See Attachment 3—Rate of Return.

Under the NER, a distributor's proposal must include the total forecast operating expenditure which the distributor considers is required in order to achieve each of the following (opex) objectives:

- meet or manage expected demand
- comply with certain obligations and service standards
- maintain the safety of the distribution system.[16]

Under the NER, we must assess ActewAGL's proposal against certain criteria and decide whether to accept it.[17] That is, we must be satisfied that the level of opex reasonably reflects the costs that a prudent operator with efficient costs, using a realistic expectation of demand and cost inputs, would require to achieve the opex objectives.[18] This means that it is not ActewAGL's *actual* costs that are the central consideration. Rather, it is the costs ActewAGL would incur, if it were a prudent operator, with efficient costs and a realistic expectation of demand and cost inputs.

We recognise that ActewAGL may continue to incur costs above efficient levels. They may have contracts (such as enterprise bargaining agreements) and practices in place that affect how they reduce costs. We consider that, in accordance with the NEO, shareholders should bear the costs of inefficiencies not consumers. Consumers should pay no more than necessary for safe and reliable electricity services. Our final decision is for a total opex allowance of $240.3 million compared to $371.2 million proposed by ActewAGL in its revised regulatory proposal. In revenue terms, this is $131 million, or 35 per cent difference between the revised regulatory proposal and the final decision.

This is the second time we have set an opex forecast for ActewAGL. For this regulatory period we have access to a consistent body of evidence that indicates that ActewAGL's historical costs are above a level that would reasonably reflect the opex criteria going forward. This evidence includes:

- various forms of benchmarking[19]
- detailed reviews by independent consultants of ActewAGL's labour and vegetation management practices.

All of this indicates that ActewAGL's distribution services could be provided at substantially lower cost while still maintaining safety and complying with reliability obligations.

In its revised proposal, ActewAGL based its opex forecast on its historical costs. Given the evidence outlined above, we are not satisfied that those forecasts are the appropriate starting point for forecasting its opex for 2015–19.

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16 NER, cl. 6.5.6(a).

17 The opex criteria - NER, cl. 6.5.6(c).

18 NER, cl. 6.12.1(4).

19 See Attachment 7—Operating Expenditure for more details.

Instead, we have used our benchmarking analysis as the starting point for assessing ActewAGL's base level of opex. We are satisfied that our resulting opex forecast reasonably reflects the opex criteria.

When we applied our benchmarking analysis we made a number of adjustments to account for the particular characteristics of ActewAGL's network that may account for costs that are unique to the network.[20] After incorporating these adjustments we found that other distributors in the National Electricity Market (NEM) provide safe and reliable distribution services at substantially lower cost levels than what ActewAGL has proposed. This implies that the costs incurred by these distributors are a better reflection of the costs that a prudent operator of ActewAGL's network—with efficient costs and realistic expectations of demand and cost inputs would need to achieve the opex objectives.

1.3 Key issues raised in revised proposal

In its revised proposal, ActewAGL raised some overarching concerns it had with our draft determination, including:

- safety implications of our draft decision
- use of benchmarking in setting revenue allowances
- consumer engagement
- financeability
- its prices and charges are the lowest in the country
- it is the most reliable network in the NEM.

We have considered ActewAGL's views on these issues in detail in the relevant attachments. However, we consider these issues are sufficiently important that we address them briefly here.

1.3.1 Safety and reliability

ActewAGL argued that our draft decision would not provide sufficient revenue for the company to operate its system safely and reliably. We have considered ActewAGL's submissions along with those of other stakeholders. This final decision approves a revenue allowance that will fund the *efficient* costs that ActewAGL acting as a prudent operator would require to run the system safely and reliably. To the extent that ActewAGL incurs costs that are above efficient levels they should be borne by ActewAGL's shareholders and not its consumers.

We have considered safety, reliability and security in a number of ways:

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[20] For the reasons set out in attachment 7, we consider that the adjustments we have made are at least sufficient to take into account the operating environment factors that may affect ActewAGL's costs.

- our external consultant has reviewed ActewAGL's risk and governance practices
- we have considered operating environment factors, such as network conditions and other regulatory obligations, that may impact safety, reliability and security
- we have considered the reliability and security of the network when considering individual aspects of the proposal, such as step changes and expenditure on bushfire mitigation projects
- our benchmarking analysis accounts for safety, reliability and security, so that our substitute opex allowance represents the efficient costs that a prudent operator would require to run the system at the existing level of safety and reliability
- the main difference between our total capex allowance and ActewAGL's revised proposal is the capex associated with the Molonglo substation that ActewAGL proposes is required within the regulatory period. The remaining capex allowance is broadly in line with ActewAGL's revised proposal. As a result, we have largely allowed all of the capex that ActewAGL sought that is associated with safety, reliability and security issues
- the Service Target Performance Incentive Scheme (STPIS) provides incentives to distributors to efficiently maintain and improve service performance.

After making these inquiries, we conclude that ActewAGL's distribution services should be provided at substantially lower cost while still maintaining safety and complying with reliability obligations.

1.3.2 Use of benchmarking

ActewAGL rejected the way we applied benchmarking in the draft decision. In particular, ActewAGL suggested that our benchmarking data was untested and unreliable and, therefore, our benchmarking analysis should not play a role in the final determinations.

We have considered ActewAGL's submissions and the submissions made by other stakeholders about our benchmarking models and data. We have confidence in the data that we used in our benchmarking models as it was developed in conjunction with industry and it has been subject to extensive review and testing it. We note that benchmarking is a well-developed technique used extensively by regulators in many other jurisdictions. Supported by the views of our benchmarking expert, we consider our models are the best available for measuring the efficiency of the service providers.

Our benchmarking models reveal inefficiency in ActewAGL's historical opex. This is corroborated by Deloitte's findings regarding ActewAGL's labour and work force practices. Our assessment also accounted for exogenous operating environment differences beyond those captured in our benchmarking model. Therefore, we are not satisfied that ActewAGL's historical costs are the appropriate starting point for forecasting its opex for 2014–19.

In this final decision we used our preferred benchmarking model as the starting point to arrive at an alternative estimate of opex that reasonably reflects an efficient base level. Our benchmarking model was carefully chosen after considering the results of previous work, the models used by regulators in overseas jurisdictions and the main cost drivers of electricity distribution businesses. We have adopted a benchmark comparison point which has a lower efficiency score than the frontier service provider. The benchmark comparison point for our final decision is AusNet Services.

This approach is consistent with our Expenditure Forecast Assessment Guideline, which established a materiality threshold for making adjustments to base opex.

Our final decision approach is the same approach we applied in our draft decision except we have lowered the benchmark comparison point. Our draft decision approach used an average of the top quartile efficiency scores as the comparison point. This final decision uses the lowest point in the top quartile as the comparison point.

1.3.3 Consumer engagement

In our draft decision we identified concerns with ActewAGL's consumer engagement. In particular we noted that it was not sufficient for ActewAGL to rely solely on the willingness to pay studies to satisfy its consumer engagement obligations. We also noted that ActewAGL's consumer engagement did not begin until after it submitted its regulatory proposal.[21]

While we recognise that ActewAGL has taken additional steps since it lodged its initial proposal to improve its engagement with its consumers we consider that ActewAGL's engagement is not developed sufficiently so it can rely on it to support its regulatory proposal to the degree it has.

1.3.4 Financeability

In its revised proposal, ActewAGL raised issues related to financial viability. Specifically, ActewAGL submitted a range of material including:

- an expert's report from David Newbery submitting that sizeable opex reductions in a short period of time would negatively impact the ongoing financeability of the DNSPs and their viability as economic entities[22]
- analysis by CEG suggesting that our draft decision would result in ActewAGL having its implied credit rating downgraded.[23]

Neither the NEL nor the NER include an explicit obligation requiring us to consider the impact of our determination on the viability of the service provider in its actual circumstances. Our task is to determine the revenue that a service provider can recover from its customers with reference to an efficient and prudent level of expenditure. The service provider’s actual ownership circumstances and the financial

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[21] AER, *Draft decision, Overview*, p. 68.

[22] David Newbery, *Cambridge Economic Policy Associates: Expert Report*, January 2015.

[23] CEG, *Efficient debt financing costs*, January 2015, pp. 54–60.

structure of its shareholders are not factors that we are required to consider in fulfilling our task under the NEL or the NER.

We are satisfied that a revenue allowance that meets the requirements of the rules will provide for ActewAGL, acting as a prudent operator with efficient costs, using a realistic expectation of demand and cost inputs, with the revenue it requires to operate viably. However, to the extent that a service provider departs from such expenditure levels, it may be at greater financial risk. Since ActewAGL submitted material from consultants relating to financial viability, we have considered it and the material put forward in support of its concerns. ActewAGL's consultants have not been specific about what they mean by the terms financeability or financial viability. In our analysis we have considered whether a service provider with the benchmark level of gearing in ActewAGL's proposed circumstances would be at material risk of insolvency. We consider this to be a reasonable standard to test financial viability. We undertook analysis using our PTRM to model ActewAGL's cash flows under a number of different scenarios. We are satisfied that ActewAGL would not be at material risk of insolvency because:

- ActewAGL is subject to a stable regulatory environment that is favourable for capital raising[24]
- we are not persuaded by CEG's analysis for the reasons set out in the appendices to the rate of return attachment.
- we are satisfied that our PTRM cash flow analysis supports this conclusion.

We discuss this analysis in greater detail in attachment 20.

1.3.5 ActewAGL's prices

ActewAGL made several representations in its revised regulatory proposal implying that its prices, or charges, are the lowest in the country. For example,[25]

> In terms of price, ActewAGL Distribution's network charges for residential customers are the lowest in the country

The key issue is not the absolute level of ActewAGL's charges, but whether the underlying costs are efficient in view of the characteristics of ActewAGL's network. As set out at Figure 3, ActewAGL's opex per customer is higher than the NEM average and materially higher than for the benchmark comparison service providers. This, in addition to our findings set out in Attachment 7, supports our view that ActewAGL is materially inefficient.

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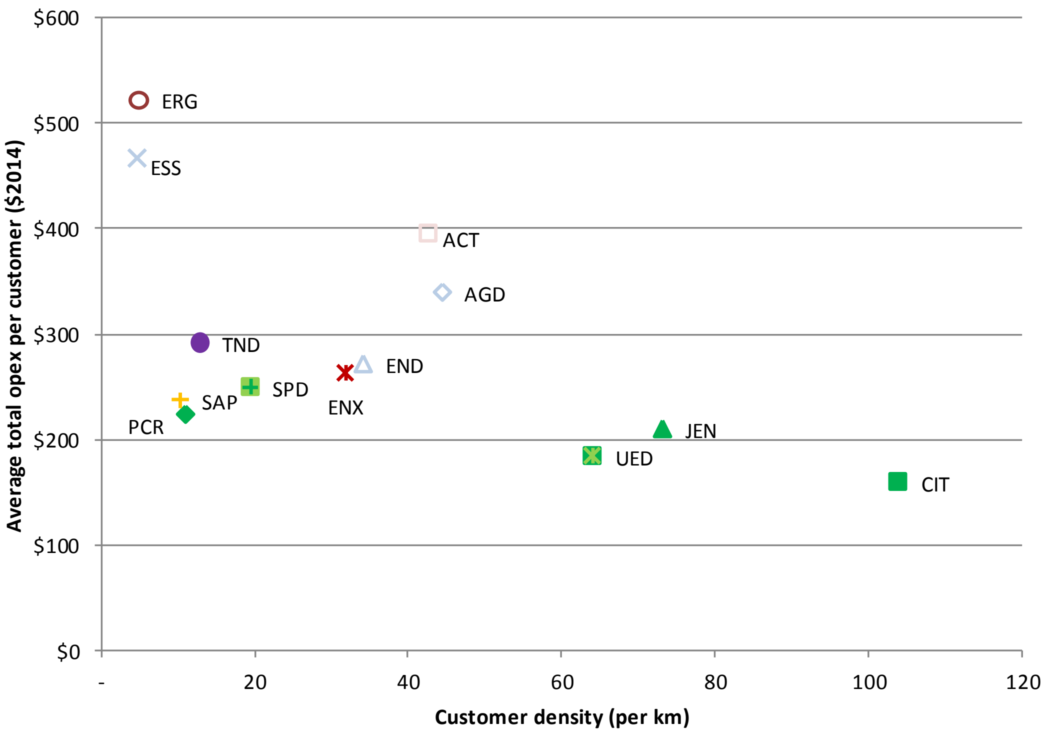
[24] For example, RARE infrastructure submitted that "[t]here are many characteristics of the Australian Regulatory framework that makes its energy network potentially attractive investments" RARE Infrastructure, *Letter to the AER*, 13 February 2015.

[25] ActewAGL, *Revised regulatory proposal*, p. 63.

While ActewAGL's revenue per customer may be among the lowest in the NEM,[26] ActewAGL’s non-residential revenue per customer is among the highest in the NEM.[27] Further, ActewAGL receives almost two thirds of all its revenue from non-residential customers, even though they make up around nine per cent of its total customer base. Nevertheless, our role is to set revenues that a service provider may recover from all its customers - residential and non-residential. We do not set prices. Revenues, however, are a significant driver of prices.

Figure 3 Average annual opex per customer for 2009 to 2013 against customer density ($2013–14)



Source: Economic benchmarking RIN data.

Note: ACT = ActewAGL, AGD = Ausgrid, CIT = CItiPower, END = Endeavour, ENX = Energex, ERG = Ergon, ESS = Essential, JEN = Jemena, PCR = Powercor, SAP = SA PowerNetworks, SPD = AusNet, TND = TasNetworks, UED = United Energy.

1.3.6 Reliability

ActewAGL made several statements that it is the most reliable network in the NEM. For example[28],

26 Economic benchmarking RIN data.

27 Economic benchmarking RIN data.

28 ActewAGL, *Revised regulatory proposal*, p. 65.

> In terms of reliability, ActewAGL Distribution has consistently been amongst the most reliable in Australia and is, importantly, the most reliable in terms of unplanned interruptions in terms of duration and frequency

The characteristics of a network are a key driver of its reliability performance. Holding everything else constant, one would expect that the greater the degree of exposed lines within a network, the greater the chance for incidences that will adversely affect reliability. ActewAGL has the largest proportion of undergrounded assets[29] and the highest proportion of urban feeders[30] in the NEM. ActewAGL's network appears to be the least exposed of all NSPs in the NEM to weather and environmental impacts on it network. As a consequence, we would expect that, for opex, ActewAGL should be able to provide reliable services at a similar cost to the benchmark comparison service providers.

Given the characteristics of ActewAGL's network, we would expect it to be one of the better performing networks on reliability and it is, on a comparison of unplanned outages. However, ActewAGL is one of the poorer performing networks on a comparison of planned outages.

1.4 Assessment of options under the NEO

The NER recognises that there may be several decisions that contribute to the achievement of the NEO. Our role is to make a decision that we are satisfied contributes to the achievement of the NEO to the *greatest* degree.[31]

For at least two reasons, we consider that there will almost always be several decisions that contribute to the achievement of the NEO. First, the NER requires us to make forecasts, which are predictions about unknown future circumstances. As a result, there will likely always be more than one plausible forecast. Second, there is substantial debate amongst stakeholders about the costs we must forecast, with both sides often supported by expert opinion. As a result, for several components of our decision there may be several plausible answers or several point estimates within a range. This has the potential to create a multitude of potential overall decisions. In this decision we have approached this from a practical perspective, accepting that it is not possible to consider every possible permutation specifically. Where there are several plausible answers, we have selected what we are satisfied is the best outcome, under the NEL and NER.

In many cases, our approach results in an outcome towards the end of the range of options materially favourable to ActewAGL (for example, our choice of equity beta). While it can be difficult to quantify the exact revenue impact of these individual

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31 NEL, s. 16(1)(d).

decisions, we have identified where we have done so in our attachments. Some of these decisions include:

- selecting at the top of the range for the equity beta
- setting the return on debt by reference to data for a BBB broad band credit rating, when the benchmark is BBB+
- the cash flow timing assumptions in the post-tax revenue model
- the point at which we have set the benchmark for opex
- the allowances we have made for operating environment factors in our benchmarking analysis

We set out our reasons in the attachments. They demonstrate that the constituent components of our decision comply with the NER's requirements. At an overall level our decision reflects the key reasons set out above, which indicate that ActewAGL should recover less revenue than it has proposed or recovered in recent years. Our decision reflects these at both the constituent component and overall revenue levels.

Given our approach, we are satisfied that our decision will or is likely to contribute to the achievement of the NEO to the greatest degree.

1.5 Structure of the overview

The remainder of this overview discusses the overarching issues in this decision, including those above, in more detail. It is structured as follows:

- Section 2 sets out the key constituent components making up our final decision.
- Section 3 sets out our decision on the classification of services, control mechanisms and incentives schemes that will apply to ActewAGL
- Section 4 explains our views on the regulatory framework
- Section 5 outlines the process we undertook in reaching our final decision

2 Key elements of the building blocks

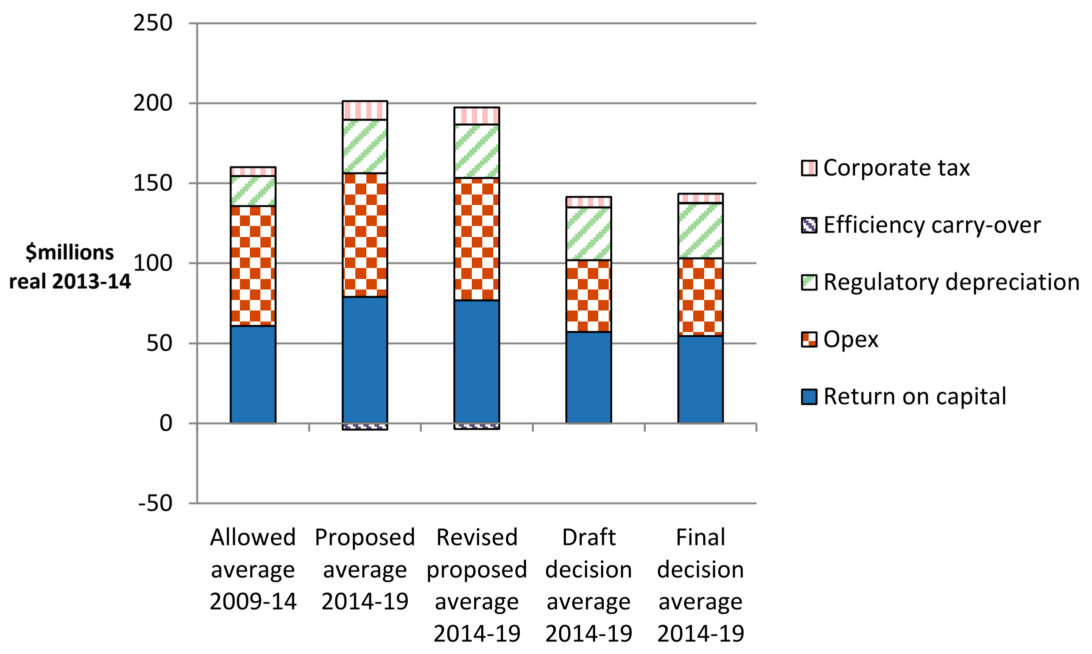
The constituent components of our decision include the building blocks we use to determine the revenue ActewAGL may recover from its customers.[32]

In setting our overall revenue for ActewAGL of $590.9 million ($ nominal) for the 2015–19 regulatory control period in relation to its distribution and transmission networks we:

- apply relevant tests under the NER, the assessment methods and tools developed as part of our Better Regulation guidelines[33] (see section 5.1). We also consider information provided by ActewAGL, the Consumer Challenge Panel (CCP), consultants and stakeholder submissions
- consider our overall revenue against section 16 of the NEL, including the constituent decisions and the interrelationships we discussed in sections 1 and 4.

Figure 4 and Table 2 show our final decision on ActewAGL's revenues.

Figure 4 AER's final decision and ActewAGL' proposed annual building block costs – distribution and transmission ($ million, 2013–14)



Source: AER analysis.

[32] NER, cl. 6.3.

[33] http://www.aer.gov.au/Better-regulation.

Table 2 AER's final decision on ActewAGL's revenues – distribution and transmission ($ million, nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Return on capital	54.9	56.9	58.7	60.8	62.3	293.6
Regulatory depreciation[a]	31.9	36.6	37.4	39.4	39.7	185.1
Operating expenditure	47.6	50.1	52.0	54.3	57.1	261.1
Revenue adjustments[b]	0.1	0.1	0.1	0.1	0.1	0.1
Corporate tax allowance	5.5	5.8	5.5	6.8	6.9	30.6
Annual revenue requirement (unsmoothed)	140.1	149.5	153.8	161.3	166.2	770.9
Annual expected revenue (smoothed)	173.2	145.7	146.9	148.4	149.8	764.1
X factor – distribution	n/a[c]	18.76%	3.00%[d]	2.50%[d]	2.00%[d]	n/a
X factor – transmission	n/a[c]	16.00%	0.00%[d]	0.00%[d]	0.00%[d]	n/a

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.

(b) Revenue adjustments relate to forecast DMIA.

(c) In our transitional decision, we determined the placeholder revenue for 2014–15. In this final decision to update the 2014–15 revenue for our assessment of efficient costs we determined X factors for the final four years of the 2014–19 period. This is to adjust ActewAGL's total revenue requirement for the 2015–19 regulatory control period for the difference between the placeholder revenue and our decision on ActewAGL's efficient costs for 2014–15.

(d) The X factor will be revised annually to reflect the annual return on debt update.

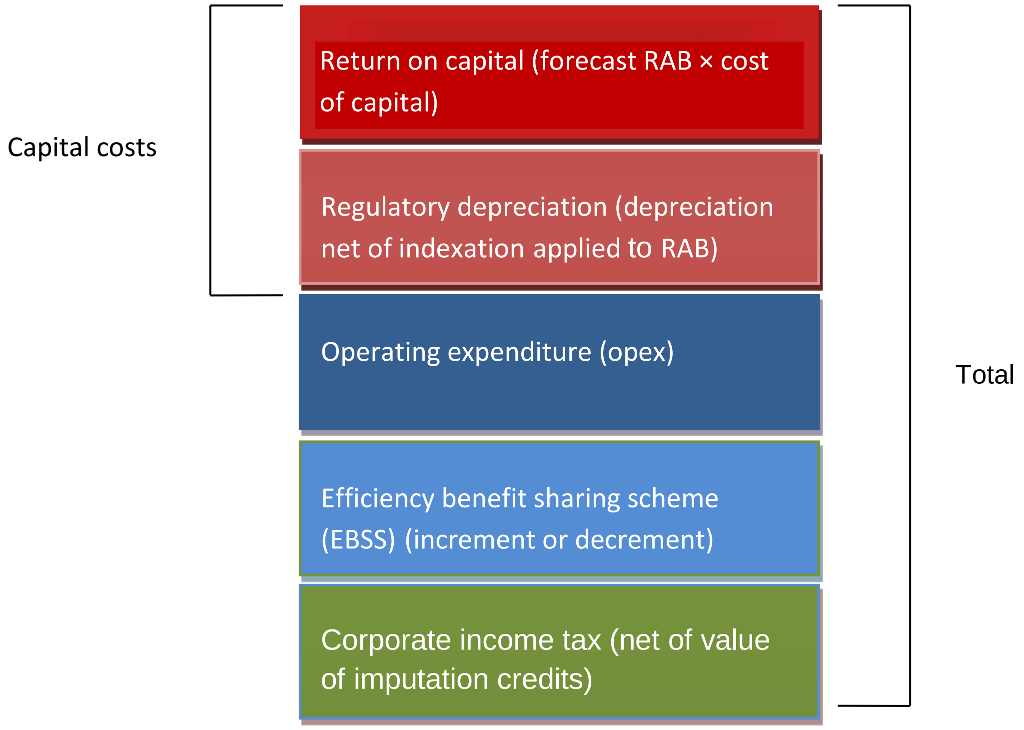
2.1 The building block approach

We have employed the building block approach to determine ActewAGL's annual revenue requirement. The building block costs, illustrated in Figure 5 include:[34]

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

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

Figure 5 The building block approach for determining total revenue



The following section summarises our decision by building block and provides our high level reasons and analysis. The attachments provide a more detailed explanation of our analysis and findings.

2.2 Regulatory asset base

The RAB is the value of ActewAGL's assets that are used to provide distribution network services. It is the value on which ActewAGL earns a return on capital, and a depreciation allowance (or a return of capital) on assets in its RAB.

We are required to assess ActewAGL's proposed opening value for the RAB for each year of the 2014–19 period.[35]

Our final decision is to accept ActewAGL's revised proposed opening RAB as at 1 July 2014 of $847.5 ($ nominal) for its distribution and transmission networks. We forecast a closing RAB at 30 June 2019 of $998.6 million for ActewAGL's distribution and transmission networks.

The forecast depreciation approach will be used to establish ActewAGL's RABs for its distribution and transmission networks at the commencement of the following regulatory control period on 1 July 2019.

35 NER, cll. 6.5.1 and S6.2.

Table 3 sets out our final decision on the roll forward of ActewAGL's RAB for its distribution and transmission networks during the 2009–14 regulatory control period.

Table 3 AER's final decision on ActewAGL's RAB for the 2009–14 regulatory control period – distribution and transmission ($ million, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	598.7	645.6	702.8	758.2	798.3
Capital expenditure[a]	66.6	72.6	69.0	67.7	85.3
Inflation indexation on opening RAB	10.9	18.4	23.8	13.4	19.6
Less: Straight-line depreciation	30.6	33.8	37.4	41.0	45.3
Closing RAB	645.6	702.8	758.2	798.3	857.8
Difference between estimated and actual capex (2008–09)					–6.7
Return on difference for 2008–09 capex					–3.5
Closing RAB as at 30 June 2014					847.5

Source: AER analysis.

(a) As incurred, net of disposals, and adjusted for actual CPI.

Table 4 sets out our final decision on the roll forward of ActewAGL's forecast RAB for the 2014–19 period in relation to its distribution and transmission networks.

Table 4 AER's final decision on ActewAGL's RAB for the 2014–19 period – distribution and transmission ($ million, nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19
Opening RAB	847.5	891.4	919.1	952.0	975.4
Capital expenditure[a]	75.8	64.3	70.4	62.7	63.0
Inflation indexation on opening RAB	20.2	21.2	21.9	22.7	23.2
Less: Straight-line depreciation	52.1	57.8	59.3	62.0	63.0
Closing RAB	891.4	919.1	952.0	975.4	998.6

Source: AER analysis.

(a) Net of forecast disposals and capital contributions.

Our assessment involved:

- Rolling forward the opening RAB at 1 July 2009 to determine the closing RAB as at 30 June 2014
- Using our final decision on forecasts of depreciation, capex, disposals and inflation for the 2014–19 period to roll forward ActewAGL's forecast RAB for each year of that period.

ActewAGL's revised proposal adopted all our draft decision adjustments to roll forward the opening RAB from 1 July 2009 to 1 July 2014. The only change ActewAGL made to the draft decision was updating 2013–14 estimated capex with actuals consistent with the annual reporting information for that year. We accept ActewAGL's revised opening RAB as at 1 July 2014 in our final decision. As part of this final decision we also forecast closing RAB values at 30 June 2019 for ActewAGL's distribution and transmission networks. We forecast ActewAGL's closing RAB to be $998.6 million ($ nominal) for its distribution and transmission networks. This is lower than forecast by ActewAGL and reflects our adjustments to:

- forecast capex (attachment 6)
- forecast depreciation (attachment 5)
- forecast inflation rate (attachment 3)

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

2.3 Rate of return (return on capital)

The return on capital provides a service provider with revenue to service the interest on its borrowings and to give a return on equity to shareholders. This building block is calculated as a product of the rate of return and the value of the RAB.[36]

The NER sets out that the rate of return must be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the service provider in respect of the provision of distribution services.[37] The NER refers to this requirement as the allowed rate of return objective .

We have determined an allowed rate of return for 2014–15 of 6.48 per cent (nominal vanilla[38]). We have not accepted ActewAGL's proposed 8.99 per cent return.[39] In accordance with the Guideline, we will update the rate of return annually, consistent

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36 NER, cl. 6.5.2(a).

37 NER, cl. 6.5.2(b).

38 The nominal vanilla rate of return formula combines a post-tax return on equity and pre-tax return on debt, for consistency with other building blocks.

39 The rate of return that ActewAGL included in its proposal is an indicative value. Its proposal includes provision for the AER to adjust this value based on updated information that was not available when ActewAGL submitted its revised proposal.

with ActewAGL's revised proposal and our approach to the return on debt.[40] Accordingly, the rate of return for 2015–16 will be 6.38 per cent.

Table 5 sets out the parameters we have used to determine the rate of return.

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

	AER decision 2009–14	AER transitional decision 2014–15	ActewAGL's revised proposal[(a)]	AER final decision 2014–15	AER final decision 2015–16	AER final decision 2016–19
Nominal risk free rate (return on equity)[(b)]	4.29%	4.30%	3.08%	2.55%	2.55%	2.55%
Equity risk premium	6.00%	4.55%	7.08%	4.55%	4.55%	4.55%
MRP	6.00%	6.50%	7.92%	6.50%	6.50%	6.50%
Equity beta	1.0	0.7	0.89	0.7	0.7	0.7
Nominal post–tax return on equity	10.29%	8.90%	10.16%	7.1%	7.10%	7.10%
Nominal pre–tax return on debt	7.78%	7.50%	7.85%	6.07%	5.91%	Updated annually[(c)]
Gearing	60%	60%	60%	60%	60%	60%
Nominal vanilla WACC	8.79%	8.06%	8.99%	6.48%[(d)]	6.38%	Updated annually[(c)]
Forecast inflation	2.47%	2.50%	2.50%	2.38%	2.38%	2.38%

Source: AER analysis; ActewAGL, *Revised regulatory proposal*, 20 January 201; AER, *ActewAGL Transitional Distribution Determination 2014–15*, April 2014; AER, *Final decision: Australian Capital Territory distribution determination 2009–10 to 2013–14*, April 2009.

(a) ActewAGL used a multi-model approach to estimating return on equity. In applying this approach, ActewAGL used single, consistent estimates of risk free rate and market risk premium but not of equity beta. However, an indicative equity beta estimate (for comparison purposes) can be calculated from ActewAGL's proposed equity risk premium and market risk premium.

(b) ActewAGL's risk free rate estimate was calculated using an averaging period of 20 business days to 19 December 2014. AER final decision risk free rate estimate is based on a 20 business day averaging period from 9 February to 6 March 2015.

(c) The allowed return on debt is to be updated annually and the nominal vanilla WACC will be updated annually to reflect the allowed return on debt. The allowed return on debt for 2014–15 and 2015–16 have already been estimated. Return on debt allowances for subsequent years will be estimated based on the formula set out in the Return on Debt Appendix to this attachment.

(d) This rate of return estimate will be used to update the revenues we previously determined for the 2014–15 (transitional) regulatory year.

[40] NER, cl. 6.5.2(i)(2).

Our approach

All NER requirements relating to the rate of return are subject to the overall rate of return achieving the allowed rate of return objective.[41] The NER recognises that there may be several plausible answers that could achieve the allowed rate of return objective.[42] We agree with stakeholders that predictability of outcomes in rate of return issues could materially benefit the long term interest of consumers.[43]

We developed our approach prior to the submission of this regulatory proposal. As required by the rate of return framework, in December 2013, we published the Guideline.[44] The Guideline was designed through extensive consultation and included effective and inclusive consumer participation.[45]

Return on debt

Previously, we used an on-the-day approach to determine the return on debt.[46] This is the approach that many Australian regulators continue to use. However, for this decision, we have determined a return on debt estimate that gradually transitions from an on-the-day approach to a trailing average approach.[47] This is consistent with the views most stakeholders expressed during the Guideline development process. We note that, ActewAGL supported by some other distributors, did not agree on the transition to the trailing average approach.

ActewAGL proposed that we use a backwards looking approach to move from the on-the-day approach to the trailing average approach. This involved using data from the last ten years to set the return on debt for the 2015–19 regulatory control period. We disagree. Instead we have determined a gradual, forward looking transition to a trailing average.[48]

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41 NER, cl. 6.5.2(b).

42 AEMC, *Rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012: National gas amendment (Price and revenue regulation of gas services) Rule 2012*, 29 November 2012, p. 67 (AEMC, *Final rule change determination*, November 2012); AEMC, *Final rule change determination*, November 2012, p. iv, AEMC, *Final rule change determination*, November 2012, p. 38; The High Court of NZ stated: 'In determining WACC, precision is therefore an elusive and perhaps non-existent quality. Setting WACC is, we suggest, more of an art than a science. The use of WACC, in conjunction with RAB values, to set prices and revenue in price-quality regulation gives significance to WACC estimates that may not exist outside this context.' *Wellington International Airport Ltd & Others v Commerce Commission* [2013] NZHC 3289, para. 1189.

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

44 NER, cl. 6.5.2(m).

45 http://www.aer.gov.au/node/18859.

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

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

48 For 2015-16, this involves 100 per cent of the return on debt reflecting the return on BBB+ rated bonds over a 10-40 business day averaging period that occurred as close as practicable to the start of the 2015–16 regulatory year. For 2016-17, this will involve 90 per cent of the return on debt reflecting the 2015-16 averaging period and 10 per

As mentioned in section 1.2, rate of return is the most material revenue difference between our final decision and ActewAGL's revised proposal. We summarise our reasons in some detail below.

We are satisfied that a gradual, forward looking transition to a trailing average approach results in a return on debt that contributes to the rate of return objective. In particular, this approach takes account of any impacts on a benchmark efficient entity or customers that might arise as a result of changing the methodology that is used to estimate the return on debt. This includes impacts that occur across regulatory control periods. In particular, a gradual, forward looking transition:

- Has regard to the impact on a benchmark efficient entity of changing the method for estimating the return on debt
- Promotes efficient financing practices consistent with the principles of incentive based regulation
- Provides a benchmark efficient entity with a reasonable opportunity to recover at least the efficient financing costs it incurs in financing its assets. And as a result it:
    - Promotes efficient investment, and
    - Promotes consumers not paying more than necessary for a safe and reliable network
- Avoids a potential bias in regulatory decision making that can arise from choosing an approach that uses historical data after the results of that historical data are already known
- Avoids practical problems with the use of historical data as estimating the return on debt during the global financial crisis is a difficult and contentious exercise.

Return on equity

Our approach to determining the return on equity involves considering all of the information before us, through a six step process as set out in the Guideline (foundation model approach). This includes detailed consideration of a number of financial models for determining the return on equity.[49] Considering all of this material helps inform a return on equity estimate that contributes to the achievement of the allowed rate of return objective.

We consider that the Sharpe–Lintner capital asset pricing model (SLCAPM) is the superior financial model in terms of estimating expected equity returns. We have

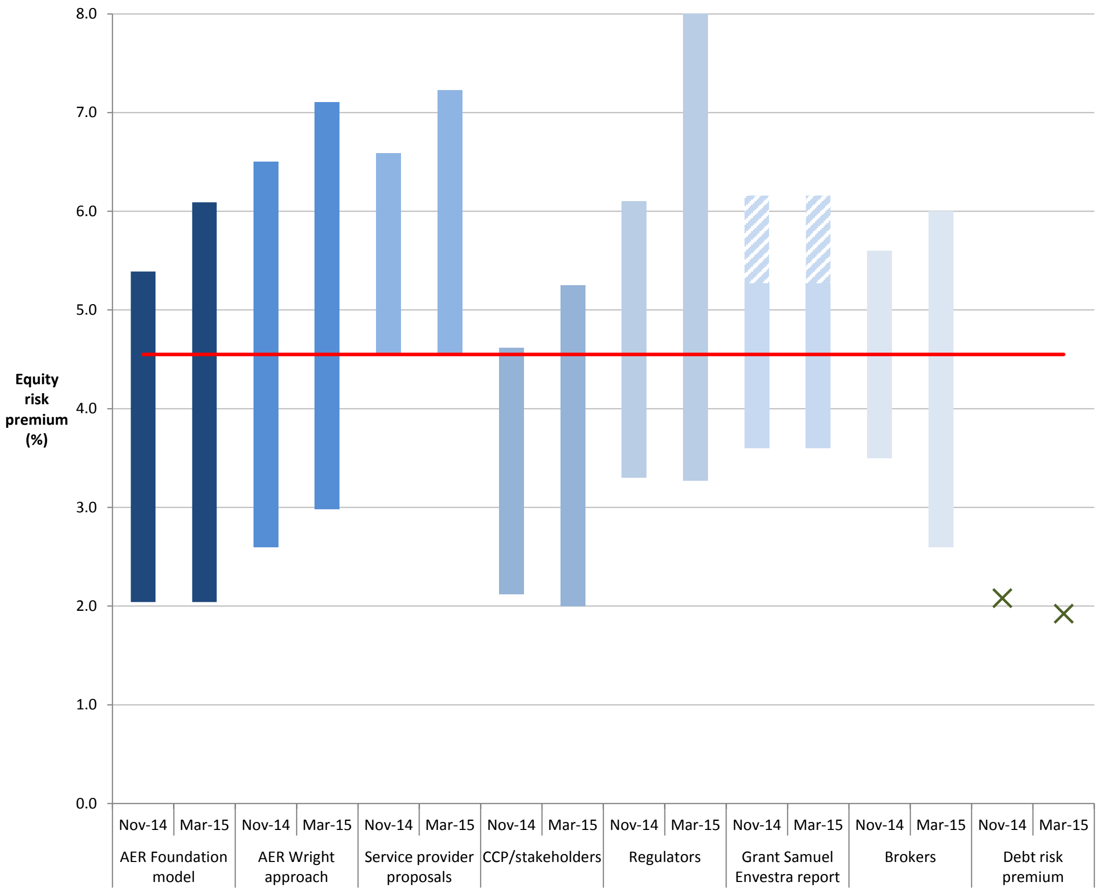
cent reflecting the 2016-17 averaging period. For 2017-18 this will involve 80 per cent of the return on debt reflecting the 2015-16 averaging period, 10 per cent reflecting the 2016-17 averaging period and 10 per cent reflecting the 2017-18 averaging period. This process will continue until, after 10 years, the entire debt portfolio has been updated and incorporated into the trailing average approach. At that point the transition is complete. This approach is the same as the transitional arrangements we proposed in the Rate of Return Guideline.

49 NER, cl. 6.5.2(e)(1).

therefore adopted this model as our foundation model. The expert evidence before us indicates that on balance employing our foundation model approach and using the SLCAPM as the foundation model is expected to lead to a rate of return that achieves the allowed rate of return objective.[50]

We also evaluated our point estimate from the SLCAPM against other information. The critical allowance for an equity investor in a benchmark efficient entity is the allowed equity risk premium (ERP) over and above the estimated risk free rate at any given time.[51] Our estimate of the ERP for the benchmark efficient entity is 4.55 per cent which is within the range of other information available to inform the return on equity (see Figure 6). A detailed explanation of our findings on return on equity and this figure can be found in attachment 3.

Figure 6 Other information comparisons with the AER allowed ERP



Source: AER analysis and various submissions and reports.

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

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

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

Grant Samuel's final WACC range included an uplift above an initial SLCAPM range. The lower bound of the Grant Samuel range shown above excludes the uplift while the upper bound includes the uplift and is on the basis that it is an uplift to return on equity. Grant Samuel made no explicit allowance for the impact of Australia's dividend imputation system. We are uncertain as to the extent of any dividend imputation adjustment that should be applied to estimates from other market practitioners. Accordingly, the upper bound of the range shown above includes an adjustment for dividend imputation, while the lower bound does not. The upper shaded portion of the range includes the entirety of the uplift on return on equity and a full dividend imputation adjustment.[52]

The service provider proposals range is based on the proposals from businesses for which we are making final or preliminary decisions in April–May 2015.[53] Equity risk premiums were calculated as the proposed return on equity less the risk free rate utilised in the service provider's proposed estimation approach.

The CCP/stakeholder range is based on submissions made (not including service providers) in relation to our final or preliminary decisions in April–May 2015. The lower bound is based on the Energy Users Association of Australia submission on NSW distributors' revised proposals. The upper bound is based on Origin's submission on ActewAGL's proposal.[54]

2.4 Value of imputation credits (gamma)

Under the Australian imputation tax system, investors can receive an imputation credit for income tax paid at the company level.[55] These are received after company income tax is paid, but before personal income tax is paid. For eligible investors, this credit offsets their Australian income tax liabilities. If the amount of imputation credits received exceeds an investor's tax liability, that investor can receive a cash refund for the balance. Imputation credits are therefore a benefit to investors in addition to any cash dividend or capital gains they receive from owning shares.

In determining a service provider's revenue allowance, the NER require that the estimated cost of corporate income tax be estimated in accordance with a formula that reduces the estimated cost by the 'value of imputation credits'.[56] That is, the revenue allowance granted to a service provider to cover its expected tax liability must be reduced in a manner consistent with the value of imputation credits.

We do not accept ActewAGL's proposed value of imputation credits of 0.25. Instead, we adopt a value of imputation credits of 0.4.

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52 Grant Samuel, *Envestra: Financial services guide and independent expert's report*, March 2014, Appendix 3.

53 ActewAGL, Ausgrid, Directlink, Endeavour Energy, Energex, Ergon Energy, Essential Energy, Jemena Gas Networks, SA Power Networks, TasNetworks, and TransGrid.

54 Energy Users Association of Australia, *Submission to NSW DNSP Revised Revenue Proposal to AER Draft Determination (2014 to 2019)*, February 2015, pp. 15–16; Origin Energy, *Submission to ActewAGL's regulatory proposal for 2014–19*, August 2014, p. 4.

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

56 NER, cll. 6.4.3(a)(4), 6.4.3(b)(4), 6.5.3, 6A.5.4(a)(4), 6A.5.4(b)(4) and 6A.6.4; NGR, rs 76(c) and 87A.

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

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

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

- The proportion of Australian equity held by domestic investors (the 'equity ownership approach').
- The reported value of credits utilised by investors in Australian Taxation Office (ATO) statistics ('tax statistics').
- Implied market value studies—there is no separate market in which imputation credits are traded, and therefore there is no observable market price for imputation credits.

In estimating the utilisation rate, we place:

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

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

- The equity ownership approach, on which we have placed the most reliance, suggests a value between 0.40 and 0.47 when applied to all equity and between 0.31 and 0.44 when applied to only listed equity. Therefore, the overlap of the evidence from the equity ownership approach suggests a value between 0.40 and 0.44.
- The evidence from tax statistics suggests the value could be lower than 0.4. Therefore, with regard to this evidence and the less reliance we place on it, we choose a value at the lower end of the range suggested by the overlap of evidence from the equity ownership approach (that is, 0.4).
- An estimate of 0.4 is reasonable in light of both higher and lower estimates from implied market value studies and the lesser degree of reliance we place on these studies. The service providers submitted evidence to support placing more reliance

on SFG's dividend drop off study relative to other implied market value studies. However, we consider that neither the difference from 0.4 of the estimate from this study (0.32) nor any increased reliance we might place on it relative to other implied market value studies are sufficient to warrant an estimate lower than 0.4.

2.5 Regulatory depreciation (return of capital)

Depreciation is the allowance provided so that capital investors recover their investment over the economic life of the asset (return of capital). We are required to decide on whether to approve the depreciation schedules submitted by ActewAGL.[57] In doing so, we make determinations on the indexation of the RAB and depreciation building blocks for ActewAGL's 2014–19 period. The regulatory depreciation allowance is the net total of straight-line depreciation (negative) less the indexation of the RAB (positive).

While we accept ActewAGL's approach to determining its regulatory depreciation, our final decision on the forecast inflation rate (attachment 3) and forecast capex (attachment 6) results in a different amount of regulatory depreciation than that proposed by ActewAGL. ActewAGL's revised proposed for regulatory depreciation allowance is $180.5 million ($ nominal) for the 2014–19 period for its distribution and transmission networks. We have determined regulatory depreciation allowance of $185.1 million ($ nominal) as shown in Table 6.

Table 6 AER's final decision on ActewAGL's depreciation allowance for the 2014–19 period – distribution and transmission ($ million, nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Straight-line depreciation	52.1	57.8	59.3	62.0	63.0	294.2
Less: inflation indexation on opening RAB	20.2	21.2	21.9	22.7	23.2	109.1
Regulatory depreciation	31.9	36.6	37.4	39.4	39.7	185.1

Source: AER analysis.

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

2.6 Capital expenditure

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

57 NER, cl. 6.12.1(8).

Our final decision is that we are not satisfied that ActewAGL's revised total capex forecast of $343.9 million ($2013–14) for the 2014–19 period reasonably reflects the capex criteria. We are satisfied that our alternative estimate of ActewAGL's total forecast capex of $310.6 million reasonably reflects the capex criteria. Table 7 outlines our final decision.

Table 7 Our final decision on ActewAGL's total forecast capex (million $2013–14)

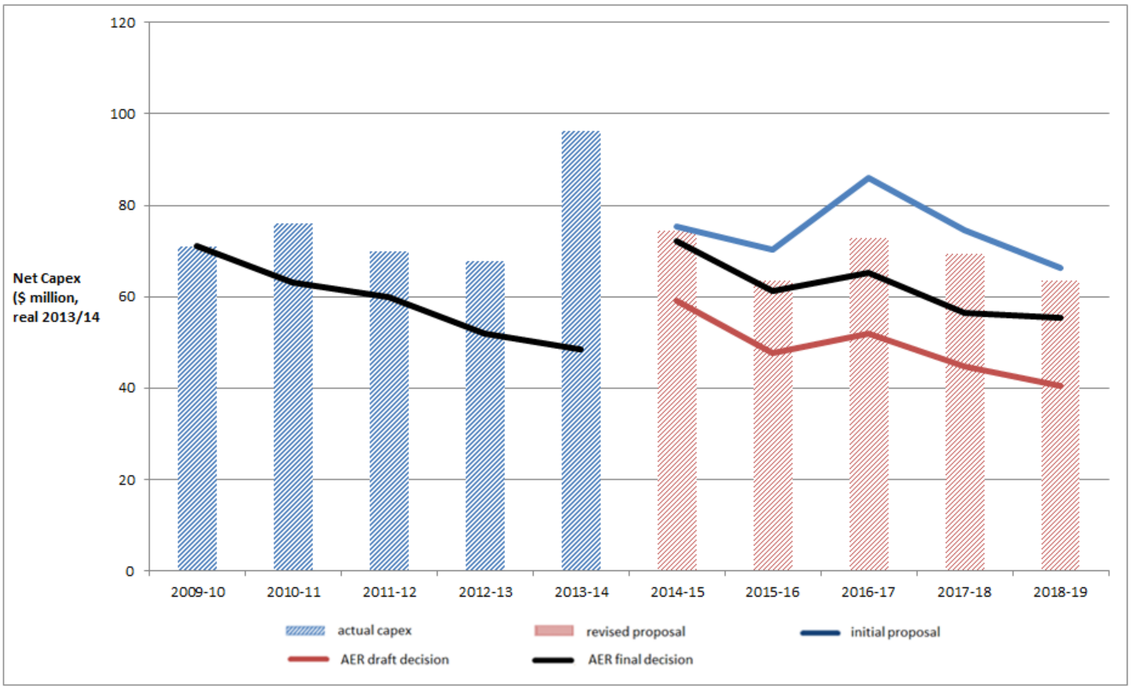
	2014–15	2015–16	2016–17	2017–18	2018–19	Total
ActewAGL revised proposal	74.5	63.6	72.8	69.4	63.5	343.9
AER final decision	72.3	61.1	65.3	56.5	55.4	310.6
Difference	-2.2	-2.4	-7.5	-13.0	-8.1	-33.3
Percentage difference (%)	-3%	-4%	-10%	-19%	-13%	-10%

Source: ActewAGL Revised Regulatory Proposal; AER analysis.

Note: Numbers may not total due to rounding.

Figure 7 shows the difference between ActewAGL's initial proposal, its revised proposal and our final decision for the 2014–19 period, as well as the actual capex that ActewAGL spent during the 2009–14 regulatory control period. The main difference between our total capex allowance and ActewAGL's revised proposal is the capex associated with the Molonglo substation. The remaining capex allowance, as discussed below, is broadly in line with ActewAGL's revised proposal.

Figure 7 ActewAGL's forecast capex, AER draft decision, and actual capex 2009–2019



Source: AER analysis.

Augmentation capex

Our final decision for ActewAGL's augex forecast is $47.1 million ($2013–14), excluding overheads. In coming to this view, we consider that ActewAGL's forecast $22.7 million for the Molonglo zone substation is not justified on the basis of the information and analysis provided by ActewAGL. Instead, we include a forecast of $2.3 million as the costs identified by ActewAGL for the construction of an additional feeder from the Woden zone substation. Our analysis, supported by an independent expert technical review, shows that the costs to consumers are minimised if the proposed Molonglo zone substation is deferred and expected demand in the 2014–19 regulatory control period is met through an additional feeder from the Woden zone substation.

We accept ActewAGL's supporting evidence for the additional capex for the zone substation earth grid upgrade, Gold Creek 11kV switchboard extension and Mitchell zone substation land purchase and include the forecast capex for these projects in our substitute estimate.

Repex

We allow $104.6 million ($2013–14) for repex, excluding overheads, which is seven per cent lower than ActewAGL's revised proposal of $112 million. The driver of this reduction is lower expenditure for cables, overhead conductor and pole top structures.

Other capex

Our final decision on other capex, is to accept ActewAGL's proposal. Specifically:

- Non-network capex—We accept ActewAGL's revised non-network capex proposal of $57.3 million ($2013–14).
- Customer connections capex—We accept ActewAGL's revised customer connections capex of $77.6 million ($2013–14).
- Capitalised overheads—We accept ActewAGL's revised capitalised overheads proposal of $52.3 million ($2013–14).

2.7 Operating expenditure

Opex includes forecast operating, maintenance and other non-capital costs incurred in the provision of network services. It includes labour costs and other non-capital costs that ActewAGL is likely to require during the 2014–19 period for the efficient operation of its network.

We are not satisfied that ActewAGL's forecast opex reasonably reflects the opex criteria.[58] We therefore do not accept the forecast opex ActewAGL included in its building block proposal.[59] We compare our alternative estimate of ActewAGL's opex for the 2014–19 period, with ActewAGL's initial proposal, our draft decision and its revised proposal in Table 8.[60]

We have increased our opex forecast by $20.3 million ($2013–14) from our draft decision. The difference between our draft decision and final decision largely reflects two main areas of change to base opex:

- a reduction in the benchmark comparison point
- different conclusions about the new and changed regulatory obligations facing ActewAGL in the 2014–19 period.[61]

Table 8 Our draft and final decision on total opex ($million, 2013–14)

	2014–15	2015–16	2016–17	2017–18	2018–19	Total
ActewAGL's initial proposal	76.7	74.9	73.0	75.6	77.1	**377.3**
AER draft decision	42.5	43.2	44.1	44.8	45.6	**220.3**
ActewAGL's revised proposal	74.8	74.2	72.3	74.3	75.6	**371.2**
AER final decision	46.1	47.3	48.0	48.9	50.3	**240.6**

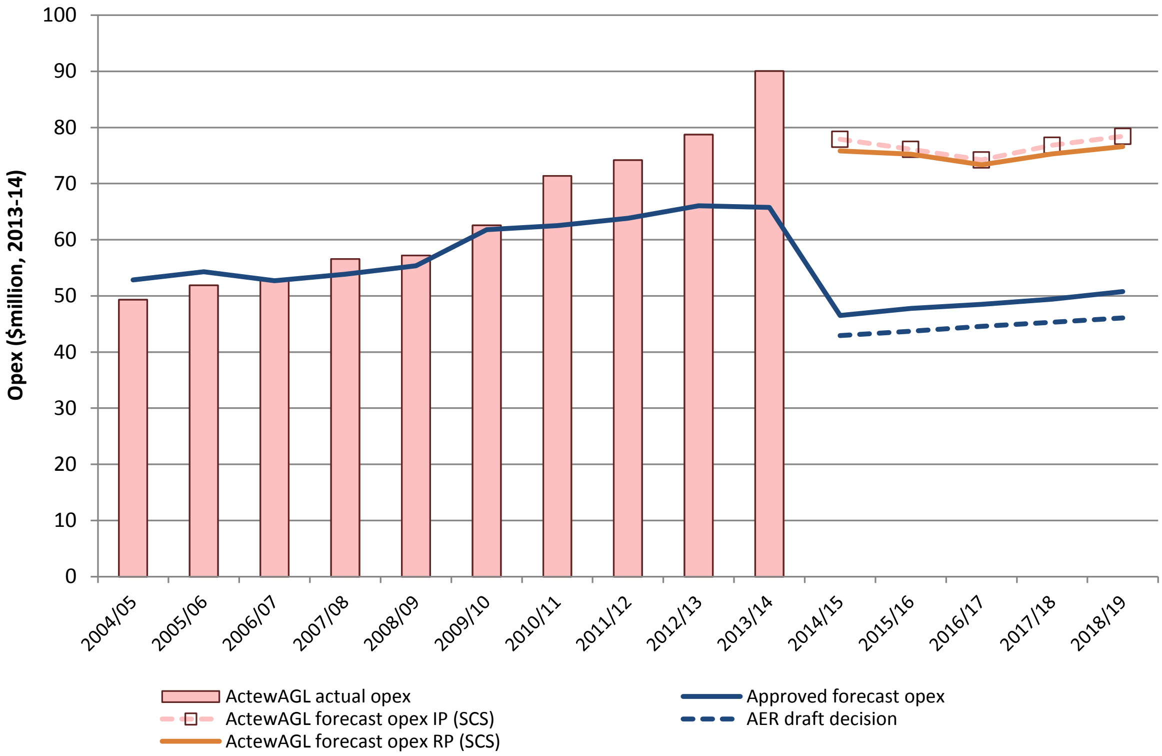
58 NER, cl. 6.5.6(c).
59 NER, cl. 6.5.6(d).
60 NER, cl. 6.12.1(4)(ii).
61 This affects step changes to base opex.

Source: AER analysis.

Note: Excludes debt raising costs.

Figure 8 shows our draft decision compared to ActewAGL's proposal, its past allowances and past actual expenditure.

Figure 8 AER final decision compared to ActewAGL's past and proposed opex ($million, 2013–14)



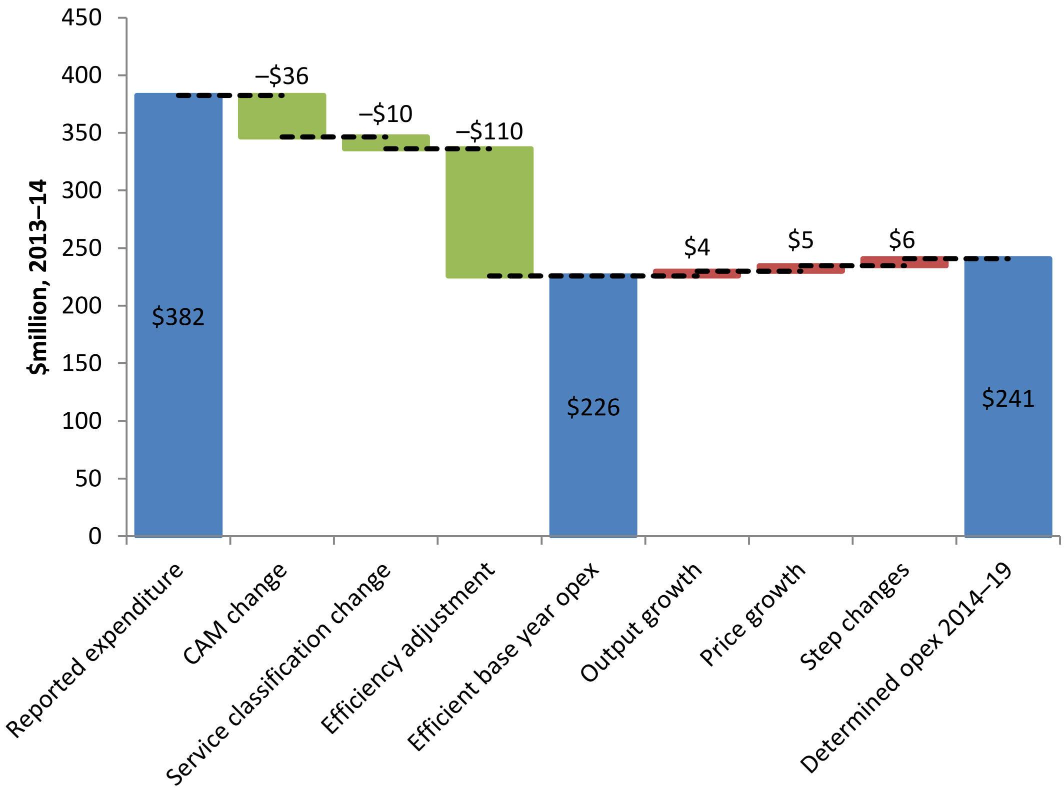
Source: ActewAGL, Regulatory accounts 2004–05; ActewAGL, Economic benchmarking - Regulatory Information Notice response 2005–06 to 2013–14.

In its revised proposal ActewAGL has forecast standard control service opex of $371.2 million ($2013–14) for the 2014–19 period (excluding debt raising costs). This is a reduction from the $377.3 million ($2013–14) it proposed in its original proposal. The reduction in opex was mainly attributable to correction of an error ActewAGL had made in its original proposal.[62]

Figure 9 illustrates how our forecast has been constructed. The starting point on the left is what ActewAGL's opex would have been for the 2014–19 period if it was set based on ActewAGL's reported base opex in 2012–13.

[62] ActewAGL, *Revised regulatory proposal*, p. 247.

Figure 9 Our final decision opex forecast



Source: AER analysis.

The primary reason for the difference between our forecast opex amount and ActewAGL's proposal reflects our views about the inefficiency of ActewAGL's recent historical performance. We do not consider that its historical performance should be used as a starting point for the forecast of opex over the 2014–19 period.

ActewAGL's proposal is based on opex it incurred in 2012–13 (the base year) in delivering standard control services. We assessed whether this is a reasonable starting point for forecasting ActewAGL's opex over the 2014–19 period. We examined ActewAGL's proposal using a number of different techniques including:

- top down benchmarking at both a total opex and category level
- detailed, qualitative reviews of ActewAGL's labour and workforce practices and vegetation management.

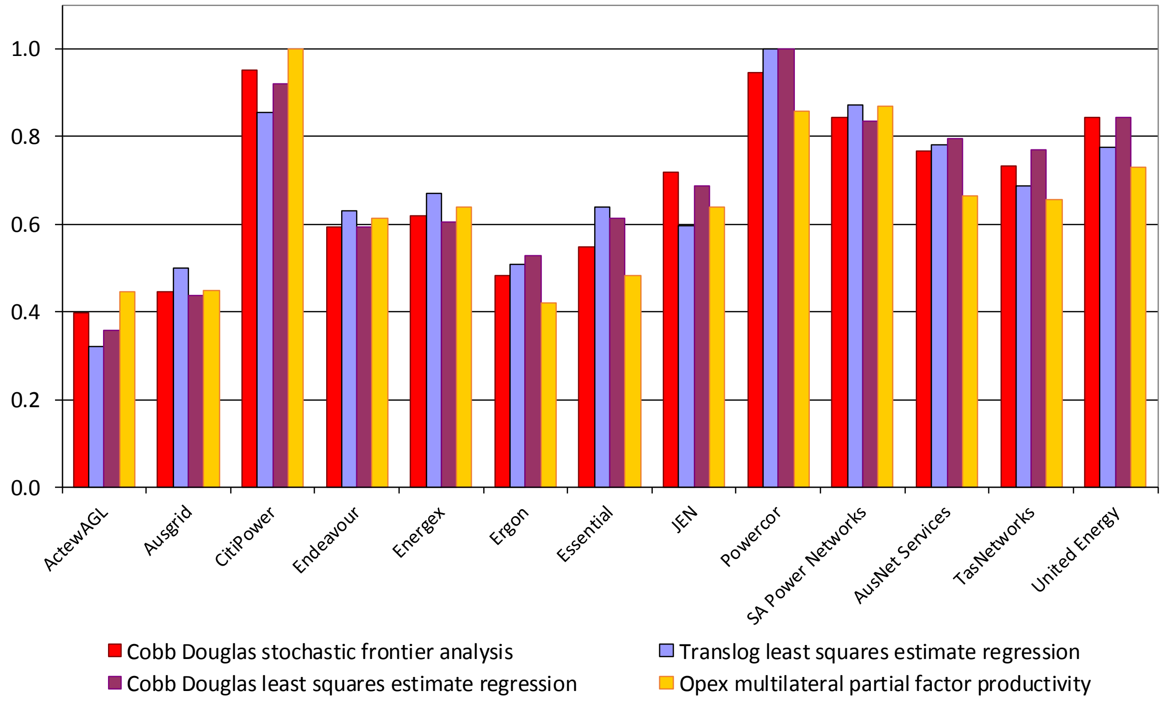
The body of evidence we assessed provided consistent evidence that ActewAGL's historical costs including those proposed in the base year are above what a prudent and efficient operator would in incur in delivering safe and reliable network services to ActewAGL's customers, given its operating environment. We did not receive any evidence in response to our draft decision that caused us to change our view on this conclusion.

Benchmarking

For this final decision, we continue to rely on the economic benchmarking techniques developed by Economic Insights for assessing the relative efficiency of service providers compared to their peers. Economic Insights developed four benchmarking techniques that specifically compare opex performance, using data submitted by the distributors, over the period 2006 to 2013.

Figure 10 presents the results of each of Economic Insights' opex models for each distributor in the NEM. A score of 1 is the best score.

Figure 10 Econometric modelling and opex MPFP results (period average efficiency scores, 2006 to 2013)



Source: Economic Insights, 2014.

We are satisfied that Economic Insights' models are the best available for assessing opex efficiency. They are sophisticated techniques and similar to those used by regulators in other jurisdictions for benchmarking relative performance.[63] Economic Insights has reviewed in detail the critiques of its models and the alternative models presented by consultants engaged by ActewAGL (and other service providers) and found its approach remains appropriate. Conversely, the alternative models presented

63 ACCC/AER (2012), Benchmarking Opex and Capex in Energy Networks, ACCC/AER Working Paper number 6, May.

by other consultants contain assumptions or limitations that mean they are not appropriate.[64]

In addition to economic benchmarking, our analysis using partial performance indicators also show ActewAGL to have higher costs than its peers.

Qualitative review

To complement our benchmarking analysis, we conducted a qualitative review of more than 80 per cent of ActewAGL's opex with the assistance of EMCa. EMCa reviewed ActewAGL's labour[65] and workforce practices and ActewAGL's vegetation management practices. We consider EMCa's findings corroborate the benchmarking results.

EMCa considers:[66]

- there is evidence that ActewAGL's work practices, processes and systems in 2012–13 were ineffective. EMCa considered that this lead to inefficient use of labour in the office and field. This inefficiency is characterised by duplication of effort in work planning and scheduling, loss of field productivity through ineffective works management and through ineffective data and information management
- ActewAGL's labour levels were not reasonably efficient in 2012–13, noting that ActewAGL has steadily increased its ASL based on assumed future growth scenarios and adopting an internal resourcing strategy. EMCa considered that if ActewAGL had outsourced more of its work, it would likely have benefited from increased labour flexibility and reduced operating costs.
- there was a lack of compelling evidence to demonstrate that ActewAGL's labour costs in 2012–13 were reflective of an efficient service provider. EMCa consider this was evident by the relatively high level of internal resources used and the extent to which work was outsourced on an hourly rate bases for the urgent clearance of vegetation.

EMCa's overall findings for vegetation management are:[67]

- ActewAGL did not act prudently and efficiently to manage costs associated with increased vegetation growth that occurred prior to 2012–13 because its vegetation management practices and its strategic and tactical responses were inadequate;
- evidence of inefficient vegetation management costs in 2012–13 exists due to the manual processes between the office and field and the extent of clearance work

[64] Economic Insights, *Response to Consultants' Reports on Economic Benchmarking of Electricity DNSPs*, April 2015, pp. iv-xi.

[65] Labour costs make up approximately 80 per cent of ActewAGL's total opex costs.

[66] EMCa, *Review of ActewAGL Distribution's Labour Resourcing and Vegetation Management Practices at 2012/13*, April 2015, pp. i-iii.

[67] EMCa, *Review of ActewAGL Distribution's Labour Resourcing and Vegetation Management Practices at 2012/13*, April 2015, pp. ii–iii.

that was deemed to be urgent, and which was therefore undertaken with a resultant higher cost. It is EMCa's view that a service provider acting to efficiently minimise costs would have incurred a lower level of urgent clearance work.

Our estimate of base opex

On the basis of the above factors, we consider that a forecast opex amount based primarily on ActewAGL's recent historical opex would not reasonably reflect the opex criteria. We have substituted ActewAGL's opex forecast with an alternative estimate that we are satisfied does reasonably reflect the opex criteria.

Our estimate of base opex is based on a benchmarking model that estimates the efficient cost of delivering network services based on a selection of cost drivers ActewAGL faces. In applying the results of this model we had further regard to over 60 potential operating environment factors that may affect ActewAGL's opex not explicitly captured in the model.

Economic Insights has also reconsidered the benchmark comparison point and decided a more cautious target is appropriate, particularly given this is the first time economic benchmarking is being used as the primary basis for an Australian regulatory decision. The benchmark comparison point is now the lowest of the efficiency scores in the top quartile of possible scores (AusNet Services).[68]

The adjustment we have made to ActewAGL's base opex includes a:

- 23.0 per cent allowance for exogenous operating environment factors
- cautious benchmark comparison point of 0.77 (rather than 0.86, which was the draft decision comparison point).

Table 9 shows our final determination estimate of efficient base year opex for ActewAGL.

Table 9 Final determination estimate of efficient base year opex ($million 2013–14)

	ActewAGL
Revealed base opex (adjusted)[a]	67.2
AER base opex	45.1
Difference	22.1

[68] Economic Insights, *Response to Consultants' Reports on Economic Benchmarking of Electricity DNSPs*, April 2015, pp. iv-xi.

Percentage opex reduction	32.8%

Note: (a) we have adjusted ActewAGL' proposed opex for debt raising costs, new CAM (if applicable) and new service classifications.

Step changes

Step changes allow for adjustments to our estimate of opex that reflects the opex criteria to account for changed circumstances in the forecast period that we have not otherwise addressed in our alternative opex forecast.

We have included $6.0 million for step changes in ActewAGL's opex forecast. This is 14 per cent of the $44.1 million which ActewAGL included in its revised proposal for step changes. ActewAGL proposed ten step changes in its revised proposal. We have accepted that two of the proposed step changes reflect new circumstances that are beyond ActewAGL's ability to control such that an increase is opex is appropriate. There were several reasons we did not accept the other step changes, in particular:

- We were not satisfied ActewAGL had adequately demonstrated it faced increased regulatory obligations or requirements in the forecast period.
- The proposals were for costs which we would typically consider to be business as usual expenses for a prudent and efficient service provider, and therefore taken into account in our estimate of base opex.

2.8 Corporate income tax

The NER require us to make a decision on the estimated cost of corporate income tax for ActewAGL's 2014–19 period.[69] The estimated cost of corporate income tax contributes to our determination of the total revenue requirements for ActewAGL over the 2014–19 period. It enables ActewAGL to recover the costs associated with the estimated corporate income tax payable during that period.

Our final decision is to determine a cost of corporate income tax of $30.6 million ($ nominal) for ActewAGL's distribution and transmission networks over the 2014–19 period as shown in Table 10. This is instead of ActewAGL's revised proposed cost of corporate income tax allowance of $55.7 million ($ nominal) for its distribution and transmission networks.

Table 10 AER's final decision on ActewAGL's cost of corporate income tax allowance for the 2014–19 period – distribution and transmission ($ million, nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	Total

69 NER, cl. 6.4.2(a)(4).

Tax payable	9.1	9.7	9.2	11.3	11.6	50.9
Less: value of imputation credits	3.7	3.9	3.7	4.5	4.6	20.4
Corporate income tax allowance	5.5	5.8	5.5	6.8	6.9	30.6

Source: AER analysis.

In our final decision we accept ActewAGL's revised proposed inputs for the opening tax asset base as at 1 July 2014, and standard and remaining tax asset lives consistent with those approved in our draft decision. However, our lower approved tax allowance reflects amendments made to other inputs that impact the estimated corporate tax allowance, including:

- the value of imputation credits (attachment 4)
- our final decision on other building block components, which affect revenues and therefore the tax calculation. These include forecast opex (attachment 7) and forecast capex (attachment 6).

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

3 Service classification, control mechanisms and incentive schemes

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

3.1 Service classification and control mechanisms

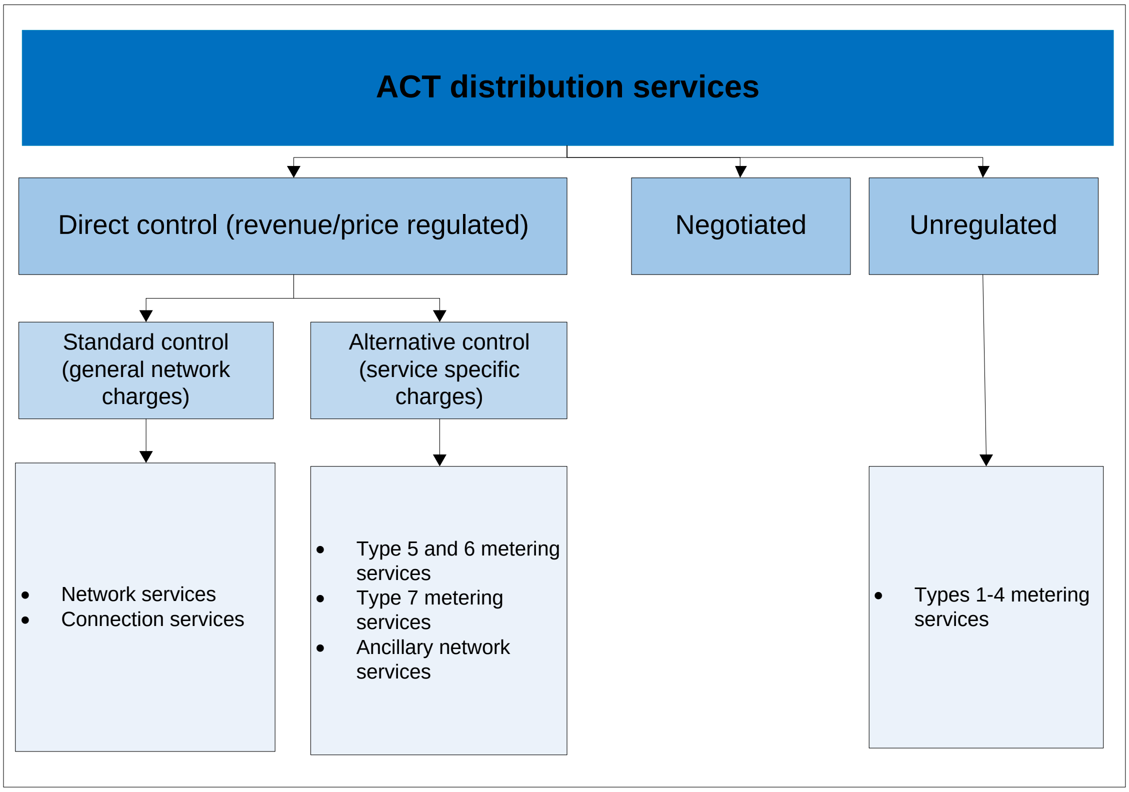
Service classification determines the nature of economic regulation, if any, applicable to specific distribution services. Classification is important to customers as it determines which network services are included in basic electricity charges, the basis on which additional services are sold, and those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

Our final decision is to retain our approach to classification as set out in our Stage 1 F&A, subject to the following:

- we separate type 7 metering services from type 5 or 6 metering services
- we classify separate type 5 or 6 metering services, one for meter reading and maintenance, and one for metering competition
- we classify a new type 5 or 6 meter transfer service
- classify large scale embedded generator connection services (above 30kWs) as alternative control services (as part of ancillary networks services)
- add 'network studies' to the list of ancillary services for clarification
- clarifying that network services include load control when provided by equipment external to a meter which is classified as standard control, but load control is part of metering services when provided by a type 5 or 6 meter which is classified as alternative control.

Figure 11 summaries our final decision on ActewAGL's service classification for the 2015−19 regulatory control period. Appendix A sets out our detailed classification decisions.

Figure 11 AER final decision on 2015–19 service classifications for ActewAGL



Source: AER analysis.

Consistent with our draft decision, ActewAGL will be subject to an average revenue cap' form of control for standard control services over the next regulatory control period. The control mechanism (which describes how the average revenues will vary from year to year) is discussed in Attachment 14. The control mechanism for standard control services is described in mathematical terms and reflects all possible adjustments that might be made to the average revenue cap.

3.2 Alternative control services

Alternative control services do not form part of ActewAGL's average revenue cap. Rather, the prices of these services are set individually. The basis of the control mechanism for alternative control services must be determined in our distribution determination.[70]

Our final decision is to maintain the approach adopted in our draft decision. That is, that the form of control mechanism to apply to ActewAGL's alternative control services

70 NER, cl. 6.2.6(b).

will be price caps.[71] ActewAGL must demonstrate compliance with the control mechanism through an annual pricing proposal.

We did not approve large upfront metering transfer or exit fees which would be a barrier to competitive entry. Instead, when a customer switches to a competitive metering provider, they will continue to pay a regulated annual charge that recovers the fixed capital costs associated with their past regulated type 5 or 6 metering service. By switching, customers may avoid the operating costs that would be charged by ActewAGL for type 5 or 6 metering services.

On 26 March 2015, the AEMC made a draft determination and draft rule in relation to the provision of metering and related services in the NEM. The rule change proposes to expand competition in metering and related services and facilitate a market led roll out of advanced metering technology.[72] We have sought to create a regulatory framework robust enough to handle the transition to competition once the rule change takes effect. This involves having transparent standalone prices for all new/upgraded meter connections and annual charges.

Our final decision does not accept ActewAGL's proposed:

- annual metering service charge, because the forecast capital and labour costs do not reasonably reflect the efficient costs of a prudent operator
- price caps for new and upgraded connections, for similar reasons
- transfer or exit fees to recover residual metering or administrative costs when customers switch to an alternative metering provider.

We accept ActewAGL's proposal to set prices on a quoted basis for those ancillary services where the service is not typical or standard, or the scope of the service is specific to particular customers' needs.[73]

We accept ActewAGL's proposed 2015–16 fee based ancillary network services. We consider the proposed fees reflect efficient costs.

We do not approve ActewAGL's labour rates for fee based and quoted ancillary network services. Our final decision for maximum total labour rates is set out in Attachment 16.

We do not approve any proposed fees for the remaining years of the regulatory control period because we do not approve ActewAGL's proposed labour escalation Instead we approve the labour escalation factor in Attachment 7—operating expenditure).

71 AER, *ActewAGL draft decision*, p. 73.

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

73 ActewAGL*, Regulatory Proposal 2015–19 Subsequent regulatory control period*, 2 June 2014 (resubmitted 10 July 2014), pp. 348–349.

3.3 Incentive schemes

Incentive schemes are a component of incentive-based regulation and complement our approach to assessing efficient costs. Under our incentive schemes, businesses are given financial rewards where they improve their efficiency and spend less than forecast during the regulatory period. Businesses may also be rewarded for efficient improvements in service quality, or be given an allowance to investigate and conduct demand management projects.

We apply incentive schemes to regulated businesses at the time of making our determinations. We decide whether to apply a particular scheme, depending on the circumstances.

The AER's four incentive schemes are:

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

3.3.1 Efficiency benefit sharing scheme

The efficiency benefit sharing scheme (EBSS) provides an additional incentive for service providers to pursue efficiency improvements in opex.

Because opex is largely recurrent and predictable, opex in one period is often a good indicator of opex in the next period (step changes provide for increases where this is not the case). Where a service provider is relatively efficient, we use the actual opex it incurred in a chosen base year of the regulatory control period (in this case 2012–13) to forecast opex for the next regulatory control period. We call this the "revealed cost approach".

To encourage a service provider to become more efficient during the regulatory control period it is allowed to keep any This is supplemented by the EBSS which allows the service provider to retain efficiency savings and efficiency losses for a longer period of time. In total these rewards and penalties work together to provide a continuous incentive for a service provider to pursue efficiency gains over the regulatory control period. The EBSS also discourages a service provider from incurring opex in the expected base year in order to receive a higher opex allowance in the following regulatory control period.[74]

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

Consistent with our draft decision, our final decision is that no expenditure will be subject to the EBSS in the 2015–19 regulatory control period.[75] The EBSS was intended to work in conjunction with a revealed cost forecast approach. Where we use benchmarking approach to forecast opex, ActewAGL will already possess a strong incentive to reduce its opex. We do not consider it is necessary to further strengthen ActewAGL's incentives to reduce its opex.

3.3.2 Capital expenditure sharing scheme

The capital expenditure sharing scheme (CESS) provides financial rewards for network service providers whose capex becomes more efficient throughout the regulatory period and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices.

As part of the Better Regulation Program we consulted on and published the Capital Expenditure Incentive Guideline, which sets out version 1 of the CESS.[76] The CESS approximates efficiency gains and efficiency losses by calculating the difference between forecast and actual capex. It shares these gains or losses between service providers and consumers.

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

The CESS is not predicated on addressing incentives resulting from a revealed cost forecasting approach. The purpose of the CESS is to provide a continuous incentive to deliver efficient overall capex and to share the benefits of capex efficiency gains (or costs of capex efficiency losses) between the distributor and consumers. The way in which capex underspends and overspends are shared occurs independently of how the EBSS applies, and independently of the precise amount of total forecast capex.[77]

We will apply version 1 of the CESS, as set out in the Capital Expenditure Incentive Guideline, to ActewAGL in the 2015–19 regulatory control period.

Attachment 10 sets out our reasons for our final decision on the CESS.

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75 This also means that no expenditure will be subject to the EBSS in the 2014–15 regulatory control period.

76 AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013.

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

3.3.3 Service target performance incentive scheme

We will apply the s-factor component of our national STPIS to ActewAGL for the 2015–19 regulatory control period. We will not apply the GSL component to ActewAGL as the existing ACT GSL arrangements will continue to apply.

The national STPIS is intended to balance the incentives to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing financial incentives to distributors to maintain and improve service performance (where customers are willing to pay for these improvements).[78] Hence, the STPIS also provides an incentive for distributors to invest in further reliability improvements (via additional capex or opex) where customers are willing to pay for it. Conversely, the STPIS penalises distributors where they let reliability deteriorate. Importantly, the distributor will only receive a financial reward after actual improvements are delivered to the customers.

In conjunction with CESS, the STPIS will ensure that:

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

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

The application of a STPIS is more important in situations where the opex allowance is based on our benchmarking analysis rather than the revealed cost approach, which relies on the distributor's historical expenditure. The use of benchmarking provides a stronger incentive for the business to reduce it costs. Arguably this means there is a greater need for STPIS to ensure that cost reductions are not at the expense of customer service. Our approved capex and opex forecasts in the final decision are sufficient to allow a prudent and efficient ActewAGL, facing a realistic expectation of the demand forecast and cost inputs, to maintain reliability at the current level.[79] The STPIS will provide an incentive for ActewAGL to maintain the current levels of reliability or to improve them where customers are willing to pay for these improvements. The STPIS balances the incentive in the regulatory framework for distributors to reduce costs at the expense of service performance.

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

[79] See section 6.4 of attachment 6, appendix A of attachment 7 and section 11.4 of attachment 11.

3.3.4 Demand management incentive scheme

The demand management incentive scheme (DMIS) includes a demand management innovation allowance (DMIA). The DMIA is a capped allowance for distributors to investigate and conduct broad based and/or peak demand management projects. 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.
- • Part B compensates distributors for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A.

We have determined to continue Part A of the Demand Management Innovation Allowance. This is consistent with our draft decision and ActewAGL's proposal that we continue to apply Part A of the DMIA at the same scale as is currently applied.[80]

The current innovation allowance amount of $0.1 million ($2014–15) per annum will continue in the 2015–19 regulatory control period.

[80] ActewAGL, *Revised Regulatory Proposal: 2015–19 regulatory control period – Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 20 January 2015, pp. 621–624 (ActewAGL, Revised Regulatory Proposal, Jan 2015).

4 Regulatory framework

The NEL and the NER provide the regulatory framework under which we operate. These set out how we must assess a regulatory proposal and make our decision. In this section we set out some key aspects of this framework.

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

> price, quality, safety, reliability and security of supply of electricity; and
>
> the reliability, safety and security of the national electricity system.[81]

The NEL also includes the revenue and pricing principles (RPP), which support the NEO.[82] As the NEL requires,[83] we have taken the RPPs into account throughout our analysis. The RPPs are:

> A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—
>
> - providing direct control network services; and
> - complying with a regulatory obligation or requirement or making a regulatory payment.
>
> A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—
>
> - efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
> - the efficient provision of electricity network services; and
> - the efficient use of the distribution system or transmission system with which the operator provides direct control network services.
>
> Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted—
>
> - in any previous—
>   - as the case requires, distribution determination or transmission determination; or

81 NEL, s. 7.

82 NEL, s. 7A.

83 NEL, s. 16(2).

- determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or

- in the Rules.

> A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.
>
> Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.
>
> Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

Consistent with Energy Ministers' views, we set revenue allowances to balance all of the elements of the NEO and consider each of the RPPs are equally vital.[84]

Chapter 6 of the NER provides specifically for the economic regulation of distributors. It includes detailed rules about the constituent components of our decisions. These are intended to contribute to the achievement of the NEO.[85] The AEMC has made clear that, in relation to key aspects of revenue, the rules guide the AER. Contrary to some submissions, these rules do not dictate any specific regulatory outcome.[86] For example, the AEMC has said:

> Some stakeholders appear to have understood the objectives as imposing on the regulator a requirement and that failure to comply with this would mean the regulator is in breach of the rules. This is not the case. Although the language of an obligation is used in some objectives, it is not necessarily expected that the substance of the objective will always be fully achieved, but rather the regulator should be striving to achieve the objective as fully as possible.

Given this framework, we consider the NEO and how to achieve it throughout our decision making processes.

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84 Hansard, SA House of Assembly, 27 September 2007, p. 965. Hansard, SA House of Assembly, 26 September 2013 p. 7173.

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

86 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18,* pp. 33–34.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp. 35-36.

4.1 Understanding the NEO

Energy Ministers have provided us with a substantial body of explanation that guides our understanding of the NEO.[87] The long term interests of consumers are not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[88]

In general, we consider that we will achieve this balance and, therefore, contribute to the achievement of the NEO, where consumers are provided a reasonable level of safe and reliable service that they value at least cost in the long run.[89] In most industries, competition creates this outcome. Competition drives suppliers to develop their offerings to attract customers. Where a supplier's offering is not attractive it risks being displaced by other suppliers.

However, in the energy networks industry the usual competitive disciplines do not apply. Distributors are largely natural monopolies. In addition, many of the products they offer are essential services for most consumers. Consequently, in an uncompetitive environment, consumers have little choice but to accept the quality, reliability and price the distributors offer.

The NEL and NER aim to remedy the absence of competition by providing that we, as regulator, make decisions that are in the long term interests of consumers. In particular, we might need to require the distributors to offer their services at a different price than they would choose themselves. By its nature, this process will involve exercising regulatory judgement to balance the NEO's various factors.

It is important to recognise that there are a number of plausible outcomes that may contribute to the achievement of the NEO. The nature of decisions under the NER is such that there may be a range of economically efficient decisions, with different implications for the long term interests of consumers.[90] At the same time, however, there are a range of outcomes that are unlikely to advance the NEO to a satisfactory extent. For example, we do not consider that the NEO would be advanced if allowed revenues encourage overinvestment and result in prices so high that consumers are unwilling or unable to efficiently use the network.[91] This could have significant longer term pricing implications for those consumers who continue to use network services.

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

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

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

90 *Re Michael: Ex parte Epic Energy* [2002] WASCA 231 at [143].
Energy Ministers also accept this view – see Hansard, SA House of Assembly, 26 September 2013 p. 7172.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18,* p. 50.

91 NEL, s. 7A(7).

Equally, we do not consider the NEO would be advanced if allowed revenues result in prices so low that investors are unwilling to invest as required to adequately maintain the appropriate quality and level of service, and where customers are making more use of the network than is sustainable. This could create longer term problems in the network[92] and could have adverse consequences for safety, security and reliability of the network.

4.2 The 2012 framework changes

This is the first decision we have made following changes to the NEL and NER in 2012 and 2013. The NEL and NER were amended to provide greater emphasis on the NEO and greater discretion to us.[93] The amended NER allows, and the AEMC has encouraged,, us to approach decision making more holistically to meet overall objectives consistent with the NEO and RPPs.[94] Also, one of the purposes of these changes was to give consumers a clearer and more prominent role in the decision making process.[95]

In 2013, the NEL was changed with similar aims in mind. The long term interests of consumers are a key focus of the changes.[96] The changes also support analysing the decision *as a whole* in light of the NEO.[97] The NEL now requires us to specify how the constituent components of our decision relate to each other and how we have taken those interrelationships into account in making our decision.[98] It also anticipates the possibility of two or more decisions that will or are likely to contribute to the achievement of the NEO. It requires that, in those cases, we must make the decision we are satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree.[99] The NER requires that we provide reasons for our decisions.[100]

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92 NEL, s. 7A(6).

93 NEL, ss. 16(1)(d) and 71P(2a)(c).
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp. i, iii, iv, vi, vii, 8, 24 32, 36, 38, 45, 49, 67, 68, 90, 96 106, 112 and 113.
Hansard, SA House of Assembly, 26 September 2013 p. 7172.

94 For example, NER, cll. 6.5.2(b) and (c), 6.5.6(a) and 6.5.7(a).
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp. xi, 10, 19, 32 and 35.

95 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* esp. pp. 166–170.

96 Hansard, SA House of Assembly, 26 September 2013 p. 7171.

97 NEL, ss. 2, 16, 71A and 71P which focus the AER's decision making and merits review at the overall decision, rather than its constituent components.
Hansard, SA House of Assembly, 26 September 2013 pp. 7171 and 7173; See also NEL, ss. 2, 16 and 71A which focus the AER's decision making and merits review at the overall decision, rather than its constituent components.
SCER, *Regulation Impact Statement – Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks*, 6 June 2013 pp. i, ii, 6–7, 10, 36, 41 and 76.

98 NEL, s. 16(c).

99 NEL, s. 16(1)(d).

The NEL does not prescribe how we are to apply these overarching requirements and so in applying them, we have exercised our regulatory judgment

We have done so by determining revenue in accordance with the detailed provisions in the NER. This assessment is in each of our attachments. As part of that assessment, and in accordance with the NEL requirements, we identify and assess the interrelationships between the constituent components of our final decision. In the following sections, we explain our approach to evaluating these interrelationships and then set out how we assessed what will contribute to the achievement of the NEO to the greatest degree. Section 1 of this overview demonstrates how we have applied these approaches for this decision.

4.2.1 Interrelationships

A distribution determination is a complex decision and must be considered as such. Considering constituent components in isolation ignores the importance of interrelationships between the components and would not contribute to the achievement of the NEO. As outlined by Energy Ministers, considering the elements in isolation has, resulted in regulatory failures in the past.[101] Interrelationships can take various forms, including:

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

We have considered interrelationships in our analysis of the constituent components of our decision. These considerations are explored in the relevant attachments.

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100 NER, cl. 6.11.2(c).

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

5 Process

The NEL requires us to inform stakeholders of the material issues we are considering and to give them a reasonable opportunity to make submissions in respect of this decision.[102]

Below we set out the process we have followed leading up to ActewAGL's submission of its regulatory proposal, to ensure that we have fully taken into account all views.

5.1 Better Regulation program

Following the 2012 changes to the NER, we spent much of 2013 consulting on and refining our assessment methods and approaches to decision making. We referred to this as our Better Regulation program. The objective of this program was to refine our approaches, with a greater emphasis on incentive regulation.[103] The Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged and provide their input.[104]

The resulting guidelines support our decision making framework as set out in section 16 of the NEL. Our consultation and engagement gives us confidence the approaches set out in the guidelines, which we have applied in this decision, will result in decisions that will or are likely to contribute to the achievement of the NEO. Our Better Regulation guidelines are available on our website and include:[105]

- Expenditure Forecast Assessment Guideline
- Expenditure Incentives Guideline
- Rate of Return Guideline
- Consumer Engagement Guideline
- Shared Assets Guideline
- Confidentiality Guideline

5.2 Our engagement during the decision making process

Effective consultation with stakeholders is essential to the performance of our regulatory functions. In summary, throughout the review process, we engaged with stakeholders by:

102 NEL, s. 16(1)(b).
103 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.
104 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.
105 http://www.aer.gov.au/Better-regulation-reform-program.

- holding monthly meetings with ActewAGL to discuss issues relevant to this decision. These meetings commenced in October 2011 to discuss the framework and approach. The meetings continued until ActewAGL lodged its revised regulatory proposal
- establishing the Consumer Challenge Panel (CCP) to assist us to make better regulatory determinations by providing input on issues of importance to consumers
- we published an issues paper on 25 July 2014 to help stakeholders engage with, and meaningfully respond to, issues in ActewAGL's regulatory proposal that we considered material to consumers
- considering 8 submissions on ActewAGL's regulatory proposal and 23 submissions on the draft decision and revised regulatory proposal
- hosting a public forum in Canberra on 30 July 2014 so stakeholders could question the AER, the CCP and ActewAGL on its regulatory proposal
- having ActewAGL present its revenue proposal to the AER Board on 5 August 2014 and revised regulatory proposal on 26 February 2015, so questions could be raised and key issues explained
- having the CCP present its advice in response to ActewAGL's regulatory proposal to the AER Board.
- convening monthly meetings between the CCP and AER staff to discuss key issues
- ongoing formal and informal jurisdictional consumer forums from February 2012
- consulting on benchmarking measures prepared by us and Economic Insights, jointly relevant to the preparation of the annual benchmarking report and our assessment of ActewAGL's regulatory proposal
- having ongoing discussions with ActewAGL about its regulatory proposal and revised regulatory proposal. In particular, our consultants and AER staff met with ActewAGL to discuss operating expenditure, capital expenditure, service classification and metering. During this process, AER staff and our consultants considered over 60 responses to information requested from ActewAGL
- hosting a workshop on treatment of metering exit fees on 11 September 2014
- a list of all submissions received during the process is included at Appendix B.

6 Next steps

Following publication of this final decision, ActewAGL will submit a 2015–16 pricing proposal. This pricing proposal will incorporate the revenues approved in this final decision into network prices from 1 July 2015.

As this decision is a reviewable regulatory decision under the NEL, ActewAGL has the right to apply to the Australian Competition Tribunal for a review of the final decision. ActewAGL may also apply for a review of the decision in the Federal Court.

Appendix A – Constituent decisions

Our final distribution determination is predicated on the following decisions (constituent decision):[106]

Constituent decision
In accordance with clause 6.12.1(1) of the NER, the following classification of services will apply to ActewAGL for the 2015–19 regulatory control period (listed by service group): • Standard control services include network services, connection services, type 5 and 6 unrecovered meter cost • Alternative control services include metering types 5 and 6 provision, installation, maintenance, reading, data services and transfer administration services, type 7 metering services and ancillary network services • Unregulated services include type 1 to 4 metering services.
In accordance with clause 6.12.1(2)(i) of the NER, the AER does not approve the annual revenue requirement set out in ActewAGL's building block proposal. Our final decision on ActewAGL's annual revenue requirement for each year of the 2014–19 period is set out in Attachment 1 of the final decision.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER approves ActewAGL's proposal that the subsequent regulatory control period will commence on 1 July 2015. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER approves ActewAGL's proposal that the length of the subsequent regulatory control period will be four years from 1 July 2015 to 30 June 2019.
In accordance with clause 6.12.1(3)(ii) and acting in accordance with clause 6.5.7(c), the AER does not accept ActewAGL's proposed total forecast capital expenditure of $343.9 million ($2013–14). Our substitute estimate of ActewAGL's total forecast capex for the 2014–19 period is $310.6 million ($2013–14). This is discussed in Attachment 6 of the final decision.
In accordance with clause 6.12.1(4)(ii) and acting in accordance with clause 6.5.6(d), the AER does not accept ActewAGL's proposed total forecast operating expenditure inclusive of debt raising costs of $376.3 million ($2013–14). Our substitute estimate of ActewAGL's total forecast opex for the 2014–19 period is $243.0 million ($2013–14). This is discussed in Attachment 7 of the final decision.
In accordance with clause 6.12.1(4A)(i) the AER determines that there are no contingent projects for the purposes of the distribution determination.
ActewAGL did not include any proposed contingent projects in its regulatory proposal for the 2015–19 regulatory control period. Therefore, • in accordance with clause 6.12.1(4A)(ii), the AER has not made an assessment of whether the capital expenditure proposed in the context of each contingent project reflects the capital expenditure criteria and factors • in accordance with clause 6.12.1(4A)(iii), the AER does not specify any trigger events in relation to contingent projects • in accordance with clause 6.12.1(4A)(iv), the AER does not determine that any proposed contingent project is not a contingent project.
In accordance with clause 6.12.1(5) the AER's decision on the allowed rate of return for the 2014–15 regulatory year in accordance with clause 6.5.2 is not to accept ActewAGL's proposal of 8.99 per cent. Our decision on the allowed rate of return for the 2014–15 and 2015–16 regulatory years are 6.48 and 6.38 per cent, respectively as set out in Table 1 of Attachment 3 of the final decision. The rate of return for the remaining regulatory years 2016–19 will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates

106 NER, cl. 6.12.1.

Constituent decision
annual updating of the allowed return on debt.
In accordance with clause 6.12.1(5A) the AER's decision is that the return on debt is to be estimated using a methodology referred to in clause 6.5.2(i)(2) which is set out in Attachment 3 of the final decision.
In accordance with clause 6.12.1(5B) the AER's decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.4. This is set out in Attachment 4 of the final decision.
In accordance with clause 6.12.1(6) the AER's decision on the regulatory asset base as at 1 July 2014 in accordance with clause 6.5.1 and schedule 6.2 is \$693.5 million for ActewAGL's distribution network and \$154.0 million for its transmission network. This is set out in Attachment 2 of the final decision.
In accordance with clause 6.12.1(7) the AER does not accept ActewAGL's proposed corporate income tax of \$55.7 million for its distribution and transmission networks. Our decision on ActewAGL's corporate income tax is \$30.6 million (\$ nominal) for ActewAGL's distribution and transmission networks over the 2014–19 period.
In accordance with clause 6.12.1(8) the AER's decision is not to approve the depreciation schedules submitted by ActewAGL. This is set out in Attachment 5 of the final decision.
In accordance with clause 6.12.1(9) the AER makes the following decisions on how any applicable efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS), service target performance incentive scheme (STPIS), demand management and embedded generation connection incentive scheme or small-scale incentive scheme are to apply: • In accordance with clause 6.12.1(9) of the NER, the AER's final decision is that no expenditure incurred by ActewAGL will be subject to version 2 of the EBSS in the 2015–19 regulatory control period. • In accordance with clause 6.12.1(9) of the NER, the AER will apply the CESS as set out in version 1 of the capital expenditure incentives Guideline to ActewAGL in the 2015–19 regulatory control period. • In accordance with clause 6.12.1(9) of the NER, the AER's *Electricity distribution network service providers, Service target performance incentive scheme, November 2009* (STPIS) will apply to ActewAGL in the 2015–19 regulatory control period. ○ The AER will apply the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) reliability of supply parameters. The AER will also apply the telephone answering parameter. As ActewAGL must comply with the existing ACT jurisdictional Guaranteed Service Level (GSL) scheme, the STPIS GSL scheme will not apply to ActewAGL. ○ A beta of 2.5 will be used to calculate the major event day boundary. ○ The AER's determinations on the SAIDI and SAIFI targets to apply to ActewAGL in the 2015–19 regulatory control period are set out in Tables 11.1 and 11.2, respectively, of Attachment 11 of the final decision. ○ Our decision on the customer service component performance target and incentive rate are set out in section 11.1.1 of attachment 11 of this final decision. ○ The revenue at risk will be capped at ±2.5 per cent. Within this there will be a cap of ±0.25 per cent on the telephone answering parameter for performance. ○ The value of S_t for 2015–16 and 2016–17 regulatory years shall be zero. The value for S_t from 2017–18 onwards shall be calculated in accordance with Appendix C of the AER's *Service target performance incentive scheme, November 2009*. Note: The meaning for year “t” under the price control formula for this determination is different to that in Appendix C of STPIS. Year “t+1” in Appendix C of STPIS is equivalent to year “t” in the price control formula of this decision. • In accordance with clause 6.12.1(9) of the NER, the AER has determined to continue Part A of the Demand Management Innovation Allowance (DMIA) for ActewAGL in the 2015–19 regulatory control period. • In accordance with clause 6.12.1(9) of the NER, the AER's decision is that no small-scale incentive scheme is to apply to ActewAGL in the 2015–19 regulatory control period.
In accordance with clause 6.12.1(10) the AER's decision is that all appropriate amounts, values and inputs are as set out in this determination including attachments.
In accordance with clause 6.12.1(11) the AER's decision on the form of control mechanisms (including the X factor) for

Constituent decision
standard control services is an average revenue cap. The average revenue cap for any given regulatory year is the average annual revenue cap (AARC) (for distribution services) for that regulatory year (calculated using the formula in attachment 14). This is discussed at attachment 14.
In accordance with clause 6.12.1(12) the AER's decision on the form of the control mechanism for alternative control services is to apply price caps. This is discussed in attachment 16.
In accordance with clause 6.12.1(13), to demonstrate compliance with its distribution determination, ActewAGL must provide to us information relating to the average annual revenue cap in its annual pricing proposal. This is set out at attachment 14.
In accordance with clause 6.12.1(14) the AER's decision on the additional pass through events that are to apply is to not accept the nominated pass through events as drafted by ActewAGL. The AER substitutes its own definitions for the following events: • insurance cap event • natural disaster event • terrorism event • insurer credit risk event. This is set out at attachment 15.
In accordance with clause 6.12.1(15) the AER's decision is to approve ActewAGL's proposed negotiating framework. The negotiating framework that is to apply to ActewAGL is set out at attachment 17 of the final decision.
In accordance with clause 6.12.1(16) the AER's decision is to apply the negotiated distribution services criteria published in September 2014 to ActewAGL. This is set out is at attachment 17 of the final decision.
In accordance with clause 6.12.1(17) the AER's decision on the procedures for assigning retail customers to tariff classes is not to accept ActewAGL's proposed procedure. The AER's decision on the procedures for assigning retail customers to tariff classes is set out at attachment 14 of the final decision.
In accordance with clause 6.12.1(17A) the AER's decision on the approval of the proposed pricing methodology for transmission standard control services (if rule 6.25 applies) is not to accept ActewAGL's proposal. The AER's decision on the pricing methodology that is to apply to ActewAGL is set out in attachment 19 of the final decision.
In accordance with clause 6.12.1(18) the AER's decision on regulatory depreciation is that the forecast depreciation approach is to be used to establish the RAB at the commencement of ActewAGL's regulatory control period (1 July 2019). This is discussed in Attachment 2 of the final decision.
In accordance with clause 6.12.1(19) the AER's decision on how ActewAGL is to report to the AER on its recovery of designated pricing proposal charges is ActewAGL is to set these out in its annual pricing proposal. This is discussed in attachment 14 of the final decision.
In accordance with clause 6.12.1(20) the AER's decision is we require ActewAGL to maintain a jurisdictional scheme unders and overs account. It must provide information on this account to us in its annual pricing proposal as set out in attachment 14 of the final decision.
In accordance with clause 6.12.1(21), the AER approves the connection policy as proposed by ActewAGL in its regulatory proposal. This is set out at attachment 18 of the final decision.

Appendix B – List of submissions

We invited submissions on our draft decision and ActewAGL's revised proposal by 13 February 2015. In addition to the CCP, the following stakeholders made written submissions:

	Submission from	Date received	Submission on
1	ACT Civil and Administrative Tribunal	20 February 2015	ActewAGL
2	ACT Council of Social Service Inc	13 February 2015	ActewAGL
3	ActewAGL	13 February 2015	ActewAGL
4	ActewAGL	4 March 2015	ActewAGL
5	ActewAGL	30 March 2015	ActewAGL
6	AusNet Services	12 February 2015	ActewAGL
7	Australian Gas Networks	13 February 2015	ActewAGL
8	Citipower and Powercor	6 February 2015	ActewAGL
9	Energy Networks Association	13 February 2015	ActewAGL
10	Ergon Energy	13 February 2015	ActewAGL
11	Glenys Patulny	13 February 2015	ActewAGL
12	Jemena	6 February 2015	ActewAGL
13	Jemena	13 February 2015	ActewAGL
14	John Herbst	11 February 2015	ActewAGL
15	Master Builders Association	13 February 2015	ActewAGL
16	The McKell Institute	13 February 2015	ActewAGL
17	Melanie Simmons	29 December 2014	ActewAGL
18	Origin	13 February 2015	ActewAGL
19	Professionals Australia	12 February 2015	ActewAGL
20	SA Power Networks	6 February 2015	ActewAGL
21	United Energy	6 February 2015	ActewAGL
22	Vector	13 February 2015	ActewAGL
23	Wayne King	13 February 2015	ActewAGL