Revised Regulatory Proposal

2015–19 Regulatory control period

Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory

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Contents

Foreword by ActewAGL Distribution CEO

The draft decision for ActewAGL Distribution's regulatory proposal issued by the AER on 27 November 2014 represents a significant departure from what was foreshadowed by the AER through the *Better Regulation* program, following the AEMC's changes to the National Electricity Rules (the Rules).

The changes to the regulatory framework implemented through the AEMC's Rule changes and related reform program give more discretion to the AER. This discretion was largely untested until the draft decision was issued. ActewAGL Distribution acknowledges that more discretion may lead to better regulatory decision outcomes on the assumption that decisions are well-principled, transparent, accord with international best practice, and are consistent with the *National Electricity Law* (NEL). However, this assumption does not hold true for the AER's draft decision for ActewAGL Distribution when, for example, the AER:

- Imposes opex reductions of 42 per cent based solely on econometric benchmarking results using unreliable data. We were repeatedly informed by the AER that it would use benchmarking cautiously. It has not. It has been bold and reckless;
- Imposes capex reductions of 35 per cent on the basis of flawed analysis and incorrect data;
- Expects largely fixed-cost network businesses like ActewAGL Distribution to make extreme adjustments to its operations in an unduly short timeframe to meet excessive cuts in its expenditure allowance;
- Unexpectedly departs from its prior regulatory practice for determining expenditure allowances on a retrospective basis. As a consequence, expenditure allowances for ActewAGL Distribution for the subsequent regulatory period are materially lower than even the AER's own estimates of efficient costs for the period; and
- Fractures the strong regulatory incentives otherwise in place for the businesses to reveal efficient costs and abandons the Efficiency Benefit Sharing Scheme (EBSS), the scheme developed by the AER to achieve a fair sharing of efficiency gains and losses between consumers and network businesses. Again, the AER provides no mechanism to compensate for this.

There is nothing wrong with attempting to deliver price reductions based on well-founded rationale and analysis. But by law the AER must consider price, amongst a number of other factors that include reliability, quality, safety, and reliability in its decision making. Our customers also value quality and reliability.

However, when a regulator relies exclusively on unreliable techniques to set expenditure allowances that are unprecedented, it raises alarms. When a regulator relies on flawed models and incorrect data to estimate replacement capital expenditure, together with opex cuts, this does not afford ActewAGL Distribution the necessary expenditure to properly run the distribution network.

The AER's proposed opex allowance was last observed 15 years ago. We cannot fathom how the AER can expect the business to deliver reliable and secure electricity services when there has been a considerable increase in scale since then. ActewAGL Distribution is serving 40 per cent more customers and maintaining a 40 per cent higher asset base since 1999/2000.

The AER has curiously invited the business to put forward proposals on whether transitioning to an efficient level of opex is allowed. If the AER adopts its draft decision as final, the brazen and unjustified cuts in expenditure allowances without a suitable transition to a justifiable and realistic expenditure level would have negative impacts on service reliability and safety. ActewAGL Distribution asserts that the AER therefore has an obligation to establish a glide path to properly assessed expenditure levels. However, we contest the benchmarking results and the frontier adopted by the AER. The AER's benchmarking is not sufficiently reliable to draw any robust conclusions on relative levels of efficiency.

The regulator fails to consider that the impact of reductions in expenditures which would produce lower electricity prices for consumers in the short-term, are likely to lead to higher costs over the long-term and this does not promote the National Electricity Objective (NEO). This will repeat the "boom-bust" cycle observed in the past.

In making its decision, the regulator must identify and fully evaluate all the consequences there may be for consumers and investors in the long-term. The role and effectiveness of the regulator is undermined if the decisions it makes have no regard to legislative and rule requirements to consider safety, reliability and security of supply. What ActewAGL Distribution seeks is a measured, prudent and fully considered approach by the regulator.

The AER's draft decision represents a major 'step change' increase in regulatory uncertainty. Additionally, risk and uncertainty have increased substantially for energy distribution businesses in Australia through the development of off-grid solutions and disruptive technologies. ActewAGL Distribution therefore considers that if, contrary to ActewAGL Distribution's revised regulatory proposal, the AER proceeds to make its final decision on the basis of the draft decision, these factors also require assessment and compensation via an increase in the return on capital.

Adoption of the draft decision in its current form would have dramatic outcomes for consumers of electricity services in the ACT as it will negatively impact reliability and security of supply, as well as the safety of the public and staff at ActewAGL Distribution. Adoption of the draft decision would have dramatic consequences for consumers, the business, and investors. The draft decision warrants a very robust discussion to ensure that it is in the long term interests of consumers.

Our critique of the AER's draft decision, including numerous legal, economic, engineering and procedural arguments, is comprehensive.

The revised regulatory proposal ultimately promotes the long term interests of consumers as required by law.

Overview and Executive Summary

Overview

ActewAGL Distribution's revised regulatory proposal addresses matters raised by the Australian Energy Regulator's (AER's) *ActewAGL distribution determination 2015-16 to 2018-19* (draft decision), which was released on 27 November 2014.

In the draft decision the AER rejects each of the key elements of ActewAGL Distribution's regulatory proposal, which was submitted to the AER on 2 June 2014. The AER:

- Rejects ActewAGL Distribution's proposed standard control services opex for the 2014-19 period of $377.3 million ($2013/14) and substitutes its forecast $220.3 million ($2013/14) – a 42 per cent reduction.
- Rejects ActewAGL Distribution's proposed standard control services capex for the 2014-19 period of $372.2 million ($2013/14) and substitutes its forecast of $244.2 million ($2013/14) – a 34 per cent reduction.
- Rejects ActewAGL Distribution's proposed weighted average cost of capital of 8.99 per cent (nominal vanilla) and instead adopts its estimate of 6.88 per cent.
- Rejects ActewAGL Distribution's proposed revenue requirement for standard control distribution services and determines a revenue requirement which is 28 per cent lower than the proposal.
- Rejects ActewAGL Distribution's consumption forecast for the regulatory period and adopts its own forecast which is on average 4.48 per cent higher than ActewAGL Distribution's forecast per year.
- Abandons the operation of the Efficiency Benefit Sharing Scheme (EBSS) for the 2009-14 regulatory period and the forthcoming regulatory period, thereby retrospectively undermining the regulatory incentive framework.

The magnitude of the reductions in expenditure allowances by the AER in its draft decision, relative to those proposed by ActewAGL Distribution in its regulatory proposal, and those allowed for previous regulatory periods, is unprecedented in the regulation of electricity network businesses in Australia.

The effect of these reductions is exacerbated by the fact that the draft decision is retrospective in nature, which means that one year of the five year period for which the AER is determining expenditure allowances will be almost completed at the time of the AER's final decision.

The AER’s draft decision reduces ActewAGL Distribution’s opex to levels not seen since before 1999 and capex to levels last seen in 2007/08, despite an approximate 40 per cent increase in customer numbers, and close to a 40 per cent increase in new assets that now form part of ActewAGL Distribution’s electricity network. These higher measures of output over the same period necessitate a higher level of opex and capex to provide a safe, reliable and secure supply of electricity.

ActewAGL Distribution contends that the AER’s expenditure allowances, if reflected in the AER's final decision, will deliver a short-term reduction in prices at the cost of a significant compromise to the long term interests of consumers with respect to reliability, security and safety.

The AER has failed to properly consider the adverse impacts of its draft decision on the long term interests of consumers, and has failed to take account of the interactions between elements of its decision – for example the impacts of opex reductions on service standards and safety and the impacts of capex reductions on opex requirements. In making the draft decision the AER has made several errors of law. For example, the AER’s draft decision to reduce ActewAGL Distribution’s base year opex proposal by 36.8 per cent, on the basis of benchmarking results, is not in accordance with law. Other key decisions such as the return on debt also involve errors of law.

In contrast to the AER’s draft decision, ActewAGL Distribution’s revised regulatory proposal would result in sustainably low prices and the maintenance of consumers’ long term interests with respect to reliability, security and safety. In addition, each element of ActewAGL Distribution's revised regulatory proposal is in accordance with law and reflects the revenue and pricing principles (RPPs). It follows that ActewAGL Distribution’s revised regulatory proposal is to be preferred to the draft decision in making a contribution to the National Electricity Objective (NEO).

ActewAGL Distribution has made the following revisions to its building block proposal in response to the draft decision:

- WACC - updates in market movements due to lower risk free rates than in ActewAGL Distribution’s regulatory proposal for the subsequent regulatory period.
- Tax – the proposed gamma is unchanged, but the notional tax allowance is lower primarily due to lower capital contributions and a return on capital (that make up the calculation of the notional tax payables).
- Capex - further assessment of project justifications, including costs and timing, and any reclassification of costs between opex and capex.
- Opex – move to a base-step-trend forecasting approach for all opex, minor adjustments to the base year, updated labour cost escalators, adjustments to the proposed corporate services charge step change and the inclusion of an additional step change.

- Other – general updates to underlying models, improved analyses and correction of errors.

A comparison of key elements of ActewAGL Distribution's regulatory proposal, the AER's draft decision and the revised regulatory proposal is provided in Table 0.1.

Table 0.1 Comparison of ActewAGL Distribution's proposals and the AER's draft decision – standard control services ($nominal)

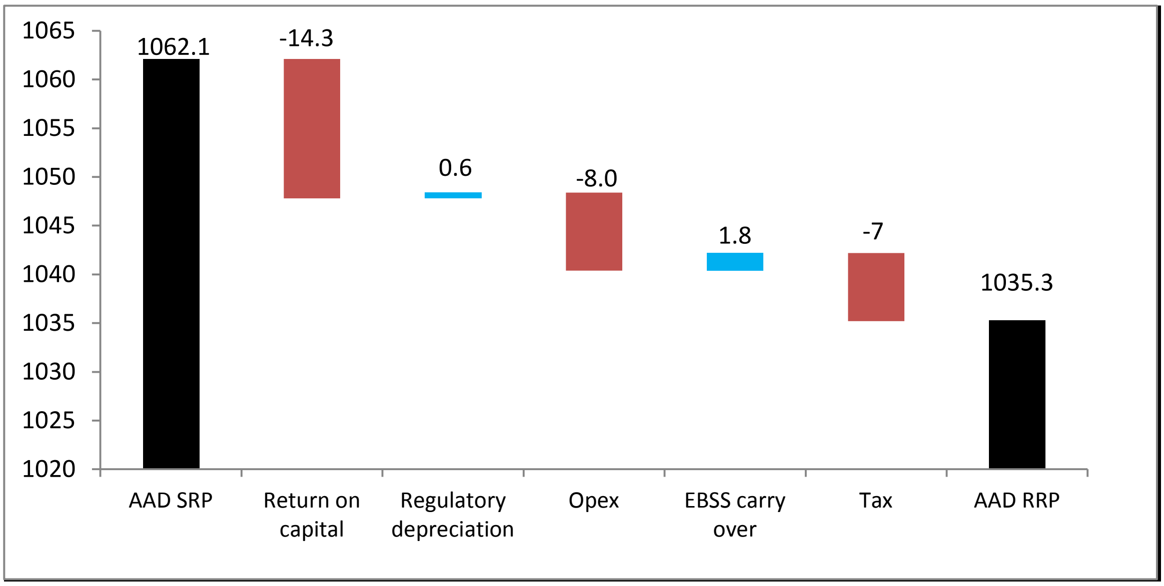
$ million (nominal)	*ActewAGL Distribution's regulatory proposal*	*AER draft decision*	*ActewAGL Distribution's revised regulatory proposal*	*Variance^ ($)*	*Variance (%)*
Revenue building blocks					
Return on capital	425.6	307.4	411.3	-14.3	-3.4%
Regulatory depreciation	179.9	177.0	180.5	+0.6	+0.4%
Operating expenditure	414.2	240.6	406.2	-8.0	-1.9%
EBSS carry over amounts	-20.2	0.0	-18.4	+1.8	+9.1%
Tax allowance	62.7	35.8	55.7	-7.0	-11.2%
Total revenue building block (unsmoothed)	**1,062.2**	**760.8**	**1,035.3**	**-26.9**	**-2.5%**
Smoothed revenue requirement	**1,065.3**	**754.9**	**1,036.2**	**-29.1**	**-2.7%**
Other key decision elements					
Energy forecast (MWh)	13,822,332	14,442,268	13,963,046	+140,714	+1.0%
Net Capital expenditure ($2013/14)*	372.2	244.2	341.4	-30.8	-8.3%
WACC	8.99%	6.88%	8.84%		-0.15bp

**Excluding equity raising costs*

^ Between regulatory proposal and revised regulatory proposal

Figure 0.1 below illustrates the revenue requirement proposed by ActewAGL Distribution in the revised proposal relative to that set out in its regulatory proposal for the subsequent regulatory control period for standard control services, and movements in each revenue building block that contribute to the variation between the two revenue proposals.

Figure 0.1 Total revenue requirement (unsmoothed) distribution and transmission ($million, nominal)



Further details on each of the key elements of the draft decision are provided in the sections below.

The NEO preferable decision

In its draft decision, the AER discusses how the constituent components of its decision relate to each other and concludes that the decision, as a whole, will contribute to the achievement of the NEO to the greatest degree (that is, it is the NEO preferable decision). ActewAGL Distribution rejects this conclusion.

ActewAGL Distribution has carefully evaluated the draft decision and engaged several experts to provide independent analysis. Based on this evaluation and analysis ActewAGL Distribution contends that:

- Various elements of the draft decision are not in accordance with law which has the necessary consequence that the draft decision is not a NEO preferable decision, and a final decision based on the revised regulatory proposal would be in accordance with law and thus to be preferred to the draft decision in contributing to the achievement of the NEO. ActewAGL Distribution asserts that:
    - The AER's primary focus on productive efficiency is not in the long term interests of consumers;

  - The primacy given by the AER to benchmarking at the expense of the other opex factors does not result in expenditure that is consistent with the NEO; and
  - There are significant broader implications of the mechanistic use of benchmarking which are not in the long term interests of consumers - it can lead to error in setting the opex allowance and also increases the potential for opex allowances that are not achievable, and which therefore do not promote the NEO.
- The retrospective application of changes in the AER's regulatory approach effected by the draft decision will result in unanticipated and material financial losses to ActewAGL Distribution which, in turn, means its effective expenditure allowances for the subsequent regulatory control period will be significantly lower than even the AER's estimate of efficient expenditure for that period. This cannot be reconciled with the scheme of the regime, the RRP or the NEO, which requires prices that support the maintenance of quality, safety, reliability and security.
- A consideration of the interrelationships between constituent components of the draft decision discloses that the various components are inconsistent with and undermine one another, with the consequence that the draft decision detracts from, rather than contributing to, the achievement of the NEO and, thus, does not constitute a NEO preferable decision. In particular, ActewAGL Distribution contends that:
  - the AER's draft decision on opex undermines the incentives that existed where the previous revealed cost approach to forecasting opex was adopted in combination with the application of an EBSS;
  - the AER's opex and capex draft decisions are inconsistent with and undermine the service quality incentive framework (STPIS); and
  - the AER has erred in not taking into consideration the inter-relationship between its opex draft decision and its capex draft decision in setting expenditure allowances.
- The expenditure allowances proposed in the draft decision do not reflect a realistic expectation of the expenditure required to achieve the opex and capex objectives set out in clauses 6.5.6(a) and 6.5.7(a) respectively of the Rules and would require drastic changes to ActewAGL Distribution's business model within an injudicious period of time, with the consequence that the draft decision, if reflected in the final decision, would deliver a short-term reduction in price but would have potentially dire consequences for reliability, security and safety. Such a decision does not contribute to the achievement of the NEO and cannot be said to be NEO preferable. By contrast, ActewAGL Distribution proposes sustainable expenditure allowances, with the result that a final decision on the basis of that revised proposal would result in sustainably low prices and the

maintenance of consumers' long term interests with respect to reliability, security and safety.

- ActewAGL Distribution was denied a reasonable opportunity to make submissions on the draft decision (as a consequence of the AER's failure to provide to ActewAGL Distribution all of the material on which it relies in that decision and its delayed provision to ActewAGL Distribution of other material on which it relies) in breach of the AER's procedural obligations and this, in turn, renders it less likely that the AER's final decision will contribute to the achievement of the NEO, particularly where that final decision maintains the draft decision.

The AER's draft decisions are affected by errors which render those decisions detrimental to the achievement of the NEO and, thus, are not NEO preferable.

By contrast, ActewAGL Distribution's revised proposals, not being affected by those errors, contribute to the achievement of the NEO and are thus NEO preferable to the AER's draft decisions.

The AER's draft decision gives effect to a number of changes in its regulatory approach that result in material financial losses for ActewAGL Distribution:

- The retrospective application of the AER's draft decision results in a notional revenue requirement for 2014/15 that is adjusted by $33.7m for distribution. A retrospective adjustment has been applied to transmission notional revenues.
- Failure to give effect to the regulatory arrangements contemplated by the application of the EBSS in the previous regulatory control period. ActewAGL Distribution's expert (HoustonKemp) estimates that to maintain the intended operation of the EBSS, the AER would need to add $36.7 million (2013/14 dollars) to AAD's 2014/15 revenues.
- Significant costs associated with restructuring the business.

ActewAGL Distribution contends that these material financial losses arising from the retrospective application of changes in the AER's regulatory approach will result in ActewAGL Distribution's effective expenditure allowances for the subsequent regulatory control period being significantly lower than even the AER's estimate of efficient expenditure for that period.

Operating expenditure

ActewAGL Distribution proposed total forecast standard control service operating expenditure (opex) of $377.3 million ($2013/14) for the 2014-19 period (excluding debt raising costs) in its regulatory proposal for the subsequent regulatory control period. This total opex forecast reflected:

- base opex for the 2014-19 period of $331.8 million ($2013/14) based on actual opex incurred in the 2012/13 revealed cost base year;
- adjustments to reflect changes in ActewAGL Distribution's cost allocation methodology;
- with step changes of $35.3 million ($2013/14); and
- forecast changes in input prices and network maintenance and vegetation management expenditure over the period.

In its draft decision, the AER concluded that it was not satisfied that ActewAGL Distribution's opex forecast reasonably reflected the opex criteria in the Rules. In particular the AER considered that ActewAGL Distribution's 2012/13 base year opex based on revealed costs did not represent that which would be incurred by an efficient and prudent service provider. The AER gave primacy to its benchmarking analysis in reaching this conclusion. The AER also determined not to apply a penalty under the EBSS arising from the additional opex spend in the current regulatory period, and to suspend the operation of the EBSS for the forthcoming regulatory period.

Accordingly, the AER rejected the opex forecast included in ActewAGL Distribution's building block proposal and substituted its own forecast of total opex of $220.3 million, which it considers reasonably reflects the opex criteria. The AER's forecast of total opex reflects a substantial reduction in base year opex, which has been mechanistically derived on the basis of its econometric benchmarking model. The AER also rejected the majority of ActewAGL Distribution's proposed step-changes, and considered that a step change of $1.4 million ($2013/14) satisfied the opex criteria, rather than the $35.3 million ($2013/14) proposed by ActewAGL Distribution.

The AER's draft decision represented an unprecedented reduction in total opex of $157 million ($2013/14) from that proposed by ActewAGL Distribution, or 41.7 per cent lower than that proposed in ActewAGL Distribution's regulatory proposal.

ActewAGL Distribution contends that the primacy given by the AER to its benchmarking analysis in assessing proposed base year opex and then mechanistically deriving its own estimate of base year opex is contrary to the statutory scheme imposed by the Rules.

Moreover, the AER's benchmarking analysis does not produce a reliable estimate of ActewAGL Distribution's efficient base opex due to numerous technical flaws in the econometric model adopted by the AER, including inadequacies in the data used. Nor are the conclusions on ActewAGL Distribution's efficiency drawn by the AER on the basis of its benchmarking analysis corroborated by the other analysis undertaken by the AER.

Further, the AER's retrospective abandonment of the EBSS undermines the incentives of the regulatory regime, increases regulatory risk and creates a framework within which perverse incentives exist. The AER's draft decision on benchmark opex is therefore not in accordance with the law, involves material errors of fact and an incorrect exercise of discretion and is unreasonable. ActewAGL Distribution maintains that the AER should set its base year opex on the basis of its actual revealed costs, and continue to apply the EBSS.

ActewAGL Distribution also maintains that the AER is incorrect in not recognising the majority of the step changes it proposed, and continues to propose step-changes in its revised opex forecast for standard control services of $44.1 million ($2013/14), as consistent with the opex criteria.

ActewAGL Distribution's revised total opex forecast is $371.2 million ($2013/14) excluding debt raising costs. This revised total opex forecast is 1.6 per cent below the regulatory proposal (excluding debt raising costs).

Table 0.2 sets out ActewAGL Distribution's regulatory proposal for forecast opex, the AER's draft decision and ActewAGL Distribution's revised regulatory proposal.

Table 0.2 ActewAGL Distribution revised total opex ($ million, 2013/14)*

$ million	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
ActewAGL Distribution regulatory 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 Distribution revised regulatory proposal	**74.8**	**74.2**	**72.3**	**74.3**	**75.6**	**371.2**

**Standard control services, excluding debt raising costs*

ActewAGL Distribution considers that its revised total opex forecast is consistent with the opex criteria in the Rules, and reflects the efficient expenditure necessary to ensure the continuing safe and reliable operation of the network. The maintenance of an approach based on revealed costs and the EBSS continues to ensure that the incentives ActewAGL Distribution faces are consistent with the achievement of long term productive, dynamic and allocative efficiency.

In the event that the AER maintains its position on opex in its final decision, then ActewAGL Distribution contends that the AER has an obligation to establish a glide path in order to transition to any lower opex allowance.

Capital expenditure

ActewAGL Distribution proposed a capital expenditure (capex) program of $372.2 million ($2013/14) for the 2014-19 period. This forecast expenditure was largely driven by the continuation of zone substation augmentation to meet demand for electricity in new urban areas and to continue to meet reliability standards, as well as an increased focus on asset renewal and replacement to address an increase in reactive maintenance in the 2009-14 period.

The AER did not accept ActewAGL Distribution's proposed total forecast capex in its draft decision, concluding that it was not satisfied that this proposed forecast capex reasonably reflects the capex criteria in the Rules. In particular the AER considered that ActewAGL Distribution's forecast of both augmentation capex and replacement capex were overstated. In some cases the AER was not satisfied that ActewAGL Distribution had provided sufficient evidence to justify the need for the expenditure. The AER substituted its own alternative estimate of total forecast capex for 2014-19 of $244.2 million ($2013/14), that is, a 34.4 per cent reduction from ActewAGL Distribution's proposed capex program.

ActewAGL Distribution has carefully reviewed the contentions put forward by the AER for rejecting its total capex forecast. ActewAGL Distribution considers that the capex programs identified in the revised proposal are necessary to ensure the ongoing safety and reliability of the network.

In this revised proposal, ActewAGL Distribution has provided additional information as requested by the AER to substantiate the efficiency of its proposed capex forecast. It has also identified a number of material errors in the analysis conducted by the AER, particularly in respect of its repex model which led it to conclude that ActewAGL Distribution's forecast total capex was inconsistent with the capex criteria.

In the process of responding to the AER's contentions, ActewAGL Distribution has corrected a number of discrepancies in the data it had previously reported to the AER.[1] ActewAGL Distribution has also reviewed the need for, scope and timing of its major augmentation projects, and has identified a number of reductions that can be made. ActewAGL Distribution has therefore revised its total forecast capex to $341 million ($2013/14), ie, 8.4 per cent below its initial proposal, to reflect both the correction of data errors and reductions in augmentation capex.

Table 0.3 sets out ActewAGL Distribution's regulatory proposal for forecast capex opex, the AER's draft decision and ActewAGL Distribution's revised regulatory proposal.

[1] Specifically: (i) revisions to the non-network capex amount due to the discrepancies identified by the AER between the figures in the PTRM and that in the RIN templates; (ii) a double-counting by ActewAGL Distribution in its RIN response of replacement expenditure relating to overhead conductors and pole top structures.

Table 0.3 ActewAGL Distribution's revised total forecast capex

($ million, $2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
ActewAGL Distribution's regulatory proposal	75.3	70.3	85.8	74.5	66.3	372.2
AER draft decision	59.2	47.8	51.8	44.8	40.6	244.2
ActewAGL Distribution's revised regulatory proposal	**74.5**	**62.6**	**71.8**	**69**	**63.1**	**341.0**

ActewAGL Distribution considers that its revised total forecast capex is consistent with the capex criteria in the Rules, and reflects the efficient expenditure necessary for ActewAGL Distribution to continue to meet its regulatory obligations in respect of safety and service levels.

ActewAGL Distribution also considers that its proposed capex forecast appropriately takes into account the interaction between opex and capex. In contrast, the AER's draft decision reduces both ActewAGL Distribution's forecast opex and its forecast repex, without taking into account the interactions between repex and opex.

Return on capital, gamma and inflation

ActewAGL Distribution proposed a return on capital of 8.99 per cent (nominal vanilla) in its regulatory proposal for the subsequent regulatory period.

In the draft decision the AER:

- was not satisfied that ActewAGL Distribution's proposed rate of return achieved the allowed rate of return objective;
- estimated an alternative rate of return of 6.88 per cent (nominal vanilla) and proposed that this be updated annually for the return on debt component;
- proposed rate of return reflects a materially lower return on equity and return on debt compared with ActewAGL Distribution's proposal;
- rejected ActewAGL Distribution's proposed gamma in its draft decision. The AER determined a gamma of 0.40 based on a distribution rate of 0.7 which in effect reflects an utilisation rate of 0.57.
- accepted ActewAGL Distribution's proposed gearing ratio.

ActewAGL Distribution maintains its position both in relation to the relevant return on equity models and evidence in relation to model parameters. However, ActewAGL Distribution has updated the estimates of model parameters and outputs based on the prevailing conditions applicable to this revised regulatory proposal. The weighting of model outputs has also been reconsidered and in the revised proposal ActewAGL Distribution applies equal weight to the return on equity models. This weighting is consistent with SFG Consulting's 'default starting point' and also recognises that no model is superior. This adjustment to the very last step of estimating the return on equity has a minor impact (downward) on the return on equity.

ActewAGL Distribution maintains its proposal that return on debt be 7.96 per cent, based on an immediate transition to a ten year averaging period. This is consistent with an efficient debt management strategy which is discussed in detail in this submission and supported by an expert report by CEG. ActewAGL Distribution also maintains its position that gamma should be 0.25, based on a distribution rate of 0.7 and an utilisation rate of 0.35.

As a consequence, ActewAGL Distribution's revised regulatory proposal includes a return on capital of 8.84 per cent.

Table 0.4 sets out ActewAGL Distribution's regulatory proposal for the return on capital, the AER's draft decision and ActewAGL Distribution's revised regulatory proposal.

Table 0.4 ActewAGL Distribution's revised WACC parameters

Component	*ActewAGL Distribution's regulatory proposal*	*AER's Draft Decision*	*ActewAGL Distribution's revised regulatory proposal*
Return on equity	10.71%*	8.1%	10.16%
Return on debt	7.85%*	6.07%	7.96%
Credit rating	*BBB*	*BBB+*	*BBB*
Gearing	60%	60%	60%
Gamma	0.25	0.4	0.25
Nominal vanilla WACC	**8.99%**	**6.88%**	**8.84%**

ActewAGL Distribution considers that its revised regulatory proposal for the return on capital is in the long term interests of consumers. It represents the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to ActewAGL Distribution, which is necessary to facilitate access to the capital market in competition with other industries and businesses for funds necessary to undertake investments in the network during the 2014-19 period.

If the rate of return allowed by the AER is less than proposed by ActewAGL Distribution, then this would likely lead the efficient benchmarking entity in ActewAGL Distribution's circumstances to not undertake or defer some of the efficient, planned network investments. Over the long-term this would result in a less reliable network and higher maintenance costs due to inefficient underinvestment in the network.

Demand and consumption forecasts

Demand

In the draft decision the AER concludes that the system demand forecasts proposed in ActewAGL Distribution's regulatory proposal reasonably reflect a realistic expectation of demand.

For the revised regulatory proposal ActewAGL Distribution has updated its demand forecasts, using the methodology used to derive the demand forecasts in its regulatory proposal for the subsequent regulatory period. Following lower-than-forecast outcomes in 2013-14, forecast system maximum demand growth has been revised downwards from 12 MVA per annum in the regulatory proposal to 7-8 MVA or 1.1 per cent per annum in this revised regulatory proposal.

Consumption

In the draft decision the AER concludes that ActewAGL Distribution's consumption forecasts are not appropriate for the purposes of making the distribution determination, due to concerns it has regarding ActewAGL Distribution's forecasting method, and determines its own alternative consumption forecasts. The AER's consumption forecasts are on average 124 GWh, or 4.48 per cent, higher than ActewAGL Distribution's forecast per year.

The AER's decision on consumption forecasts has significant implications for the ability of ActewAGL Distribution to recover its efficient costs.

In the revised regulatory proposal, ActewAGL Distribution addresses each of the AER's concerns and contends that, in rejecting ActewAGL Distribution's consumption forecast, the AER makes an error or errors of fact material to the making of its decision, incorrectly exercises its discretion in all the circumstances and/or makes a decision that is unreasonable in all the circumstances.

In the revised regulatory proposal ActewAGL Distribution therefore maintains the forecast method proposed in its regulatory proposal for the subsequent regulatory proposal and contends that this method, and not that of the AER, produces appropriate consumption forecasts for the distribution determination.

ActewAGL Distribution has revised its forecast to account for recent observations and latest available forecasts of growth in the relevant economic and demographic explanatory variables. The revised forecast is increased relative to ActewAGL Distribution's regulatory proposal for the subsequent regulatory proposal by 1.0 per cent on average over the regulatory period.

Incentive Schemes

EBSS

ActewAGL Distribution proposed a total EBSS carryover amount (penalty) of $19.6 million ($2013/14) be subtracted from its regulated revenue in the 2014–19 in accordance with the EBSS applied during the 2009-14 regulatory control period.

In its draft decision the AER determined that it will not apply an EBSS penalty to ActewAGL Distribution in respect of the 2009-14 period and that no opex will be subject to the EBSS during the 2014–19 regulatory period. The AER justified its decision to abandon the EBSS on the basis that it is intended to work in conjunction with a revealed cost forecast approach, and the AER's draft decision in respect of opex is to not to use the revealed cost approach for the 2014–19 period.

The AER also stated that ActewAGL Distribution will already face an incentive to make efficiency improvements while its actual opex is more than that of a benchmark efficient service provider and therefore the AER does not need to apply the current EBSS to further strengthen those incentives.[2]

ActewAGL Distribution contends that the AER's draft decision is flawed and inconsistent with the NEL and the Rules for the following reasons:

- It represents a retrospective change to the regulatory framework that is inconsistent with the NEO and imposes a significant financial loss on ActewAGL Distribution. The draft decision imposes 100 per cent of the costs of 2009-14 efficiency losses on ActewAGL Distribution rather than the approximate 30 per cent intended under the EBSS. ActewAGL Distribution's expert advisors HoustonKemp estimate that to maintain the intended sharing ratio of 30:70 in net present value terms would require the AER to add $36.7 million (2013/14 dollars) to AAD's 2014-15 revenues.
- Advice from HoustonKemp also demonstrates that the AER's approach to setting the opex allowance and its abandonment of the EBSS is 'deeply flawed' and creates incentive arrangements that are inconsistent with the Rules and the NEL and undermine the existing regulatory framework that had (with the introduction of the CESS) aligned the incentives for DNSPs to deliver efficient services through time;
- There is no fair sharing of efficiency gains and losses between ActewAGL Distribution and its customers, as required under the Rules. Customers will receive a 100 per cent

[2] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-12

benefit from any cost reductions achieved during the 2014-19 period until ActewAGL Distribution has achieved the AER's opex allowance.

ActewAGL Distribution proposes that the EBSS should continue to apply in the 2014-19 period; and the EBSS allowance for the 2014-2019 period should be based on the revealed cost incurred in 2012/13 excluding non-controllable operating expenditure.

However, if the AER retains its decision to set the opex on a basis other than revealed costs, then ActewAGL Distribution's revenue should be adjusted for the 2014-2019 period such that it achieves the 30:70 sharing principles underpinning the EBSS.

STPIS

The AER's draft decision is to apply the national STPIS to ActewAGL Distribution without the modifications proposed by ActewAGL Distribution in its regulatory proposal for the subsequent regulatory period in relation to the performance targets and incentive rates for the reliability component of the STPIS.

In ActewAGL Distribution's response to the AER's draft decision, it contends that:

- In determining to apply the national STPIS to ActewAGL Distribution without any modification in respect of performance targets, the AER has failed to take into account the inter-relationship between STPIS and forecast expenditure allowances, and, as a result, the draft decision will operate to impose an expected loss on ActewAGL Distribution, in the form of a STPIS penalty, which is inconsistent with clause 7A(2) of the NEL; and
- In placing primary reliance on the VCR estimated by AEMO for New South Wales, rather than on the VCR proposed by ActewAGL Distribution based on evidence from the ACT, the AER has failed to take into account the circumstances of ActewAGL Distribution and the customers or end users that ActewAGL Distribution supplies.

In this revised regulatory proposal, ActewAGL Distribution continues to propose that the national STPIS be applied to ActewAGL Distribution with modifications to the:

- performance targets for the reliability of supply component; and
- VCR used to set incentive rates for the reliability of supply component.

ActewAGL Distribution has amended its proposed performance targets in this revised regulatory proposal to account for the effects of historical expenditure. It maintains, however, its original proposal in respect of the VCR used to set incentive rates. ActewAGL Distribution also proposes that, in light of the draft decision on forecast opex and the need for ActewAGL Distribution to revise its originally proposed performance targets, that the level of revenue at risk under STPIS should now be set at ±2.5 per cent (rather than ±5 per cent) to ensure the level of revenue at risk is symmetric, with the cap on annual rewards corresponding to feasible levels of reliability.

Standard control price path and impacts

The AER's draft decision results in X-factors provided in Table 0.5 the table below for distribution and transmission services to be applied as CPI – X price adjustments.

Table 0.5 Standard control CPI – X price adjustments

	2014-15	2015-16	2016-17	2017-18	2018-19
Distribution					
AAD regulatory proposal	19.59%	–14.66%	–1.50%	–1.50%	–1.50%
AER draft decision	19.59%	28.78%	-1.50%	-1.50%	-1.50%
AAD revised regulatory proposal	19.59%	-11.5%	0%	0%	0%
Transmission					
AAD regulatory proposal	2.02%	–21.22%	–5.22%	–5.22%	–5.22%
AER draft decision	2.02%	20.69%	-2.50%	-2.50%	-2.50%
AAD revised regulatory proposal	2.02%	-27.0%	–3%	–3%	–3%

The price path proposed in the revised regulatory proposal will result in a small reduction in distribution network charges of around 3 per cent relative to ActewAGL Distribution's regulatory proposal. For a typical Canberra residential consumer using 7000 kWh per annum, it means a reduction in the distribution component of the annual bill of $13 relative to the regulatory proposal.

The revised regulatory proposal represents an annual increase—relative to current prices—of $50. This is equivalent to an increase of $0.96 per week.

AAD's residential consumers currently pay the lowest network charges in the country (on a state by state comparison) and have the lowest electricity bill.

Metering

The AER's draft decision on metering services involves significant changes to the structure of metering charges and the way in which ActewAGL Distribution recovers metering costs from its customers. Major changes are expected to be made to the Rules and the broader regulatory framework for metering during the 2014-19 regulatory period. The AER says that its draft decision aims to facilitate the transition to competition in metering and related services.

ActewAGL Distribution agrees with some aspects of the AER's draft decision. However ActewAGL Distribution is concerned that under the AER's approach to recovery of residual meter values, when customers switch to an alternative meter provider, there is a significant risk that ActewAGL Distribution will be unable to fully recover stranded asset values. The AER's approach to residual meter costs involves smearing the costs across the whole customer base through annual adjustments to network prices. In contrast, ActewAGL Distribution's proposal directly recovers the costs from those customers who choose to switch to alternative meter providers.

In this revised regulatory proposal ActewAGL Distribution:

- accepts the AER's draft decision that the full costs of new and upgraded meters should be recovered in an up-front charge to the customer requesting the meter;
- maintains its regulatory proposal that exit fees are the most transparent and effective way to recover the residual value of meters (plus administrative costs) when customers switch to alternative providers; and,
- argues that if the AER continues to reject exit fees (as it has in the draft decision), then a modified version of the AER's B factor adjustment should apply, to allow full recovery of residual meter values via network charges over the remaining 4 years of the current regulatory period.

1 Introduction

On 2 June 2014 ActewAGL Distribution submitted its regulatory proposal for the 2014-19 distribution determination to the Australian Energy Regulator (AER). The AER undertook a preliminary examination and, following ActewAGL Distribution's submission of a revised proposal on 10 July 2014, the AER on 11 July 2014 notified ActewAGL Distribution that the regulatory proposal and supporting information complied with the relevant requirements of the National Electricity Rules (NER or "Rules").[3]

The AER commenced a public consultation and review process. The review involved a public forum held on 30 July 2014 where all stakeholders where invited to participate.

The review process also involved detailed information requests from the AER. ActewAGL Distribution responded to more than 50 information requests from the AER, and engaged in a number of meetings with AER staff and the AER Board.

On 27 November 2014 the AER released the "Draft decision ActewAGL distribution determination 2015-15 to 2018-19" (draft decision). Although the AER's draft decision accepted some elements of ActewAGL Distribution's regulatory proposal several elements of the original proposal were not accepted and the AER adopted alternative values for all of the revenue building blocks.

This revised regulatory proposal addresses matters arising out of the draft decision in accordance with the requirements set out in clause 6.10.3 of the Rules.

Each element of ActewAGL Distribution's revised proposal has been developed in accordance with all relevant aspects of the Rules.

The rest of this Introduction covers:

- In Section 1.1, an overview of the legal and regulatory requirements
- In Section 1.2, the activities undertaken to engage with consumers thus far and its consumer engagement strategy going forward.

The structure of the revised regulatory proposal is covered in Section 1.3.

[3] AER letter to ActewAGL Distribution, 11 July 2014

1.1 Overview of the legal and regulatory requirements

This section summarises regulatory obligations and requirements required to be adhered to by ActewAGL Distribution which are also a substantial driver of the costs facing ActewAGL Distribution in the construction, operation and maintenance of its electricity network.[4]

Like all electricity distribution network service providers in Australia, ActewAGL Distribution is a regulated business. It must comply with the Rules and the National Electricity Law (NEL), including the National Electricity Objective (see Box 1). It must also set its distribution charges in line with the AER's determinations.

Box 1 The National Electricity Objective

The National Electricity Objective, set out in the NEL, is to:

"promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

(a) price, quality, safety, reliability and security of supply of electricity; and

(b) the reliability, safety and security of the national electricity system"

Compliance with applicable legislative and regulatory obligations and requirements associated with the provision of standard control services is one of the four objectives for capital and operating expenditure set out in the Rules.[5] The building block proposal prepared by ActewAGL Distribution under the Rules must include the total forecast capital and operating expenditure for the relevant regulatory control period, which ActewAGL Distribution considers to be required to meet the capital and operating expenditure objectives associated with the provision of standard control services.

This summary section does not set out all legislative and regulatory obligations to which ActewAGL Distribution is subject. The principal laws, regulations, rules, codes and guidelines that regulate ActewAGL Distribution's operation as an electricity utility are included, as well as other instruments with a particular impact on ActewAGL Distribution's operations as an electricity utility. ActewAGL Distribution has not sought to include in detail laws of general application to

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[4] A detailed description of the regulatory obligations and requirements was covered in Chapter 4 of ActewAGL, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period, Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July)

[5] *National Electricity Rules,* clauses 6.5.6(a)(2) and 6.5.7(a)(2)

corporations and individuals, such as the *Competition and Consumer Act*, *Corporations Act*, *Privacy Act*, intellectual property legislation or motor traffic legislation.

The synthesised discussion below focuses on territory-specific laws, rules, codes and guidelines. While they arise mainly from ACT laws, codes and guidelines, in many cases similar requirements apply in other jurisdictions. This is particularly the case for technical and safety requirements, which have their source in the Rules, Australian Standards and national codes of practice.

The application of these obligations in the ACT can differ, however, particularly in relation to some of the specific characteristics of the ACT network. These relate mainly to emergency, environmental and planning obligations.

ActewAGL Distribution is subject to a broad range of Commonwealth and territory-specific laws, as well as a number of codes and procedures established by the ICRC and other relevant regulators. These obligations fall under the following broad categories.

- Industry obligations—these are mainly associated with the characteristics of ActewAGL Distribution as a natural monopoly provider of electricity distribution services in the ACT. These include many of the obligations under the *Utilities Act 2000 (ACT)*, *Utilities (Network Facilities) Tax Act 2006 (ACT)*, *Territory-owned Corporations Act 1990 (ACT)*, *Utility Services Licence*, *Consumer Protection Code*, and Ring-fencing guidelines. These obligations mainly drive operating costs.
- Technical obligations—these are associated with the technical requirements involved in owning, managing and operating electricity network assets. These obligations include aspects of the *Utilities Act 2000 (ACT)* and codes established under that Act such as the *Management of Electricity Network Assets Code*, and a variety of relevant Australian Standards. Compliance with ActewAGL Distribution and Industry Procedures developed in accordance with these Acts also creates regulatory obligations. These obligations are a key driver of capital costs.
- Safety obligations—these are associated with the safety risks involved in owning an electricity network, and the procedures and processes required to operate, maintain and build network assets and ensure employee and community safety. Relevant instruments include *the Work Health & Safety Act 2011(ACT)*, the *Electricity Safety Act 1971 (ACT)*, the *Building Act 2004 (ACT)*, the *Construction (Occupations) Licensing Act 2004 (ACT)*, the *Scaffolding and Lifts Act 1912 (ACT)*, the *Dangerous Substances Act 2004 (ACT)*, the *Crimes Act 2000 (ACT)*, the *Utilities Act 2000 (ACT)*, and regulations, codes and procedures under these Acts. These obligations drive both capital and operating costs.
- Environment, emergency and heritage obligations—these relate to the operation of ActewAGL Distribution in the ACT environment, its responsibilities to prepare for, and act in the event of, an emergency, as well as heritage issues. Obligations arise from the *Environment Protection Act 1997 (ACT)*, the *Litter Act 2004 (ACT)*, the *Planning and*

Development Act 2007 (ACT), the *Tree Protection Act 2005 (ACT)*, the *Nature Conservation Act 1980 (ACT)*, the *Emergencies Act 2004 (ACT)*, the *Heritage Act 2004 (ACT)* and the *Native Title Act 1993 (Cwth)*. Obligations under these acts, and associated regulations and codes, drive both capital and operating costs.

- Market obligations—these relate to the role of ActewAGL Distribution as a distribution network service provider in the National Electricity Market (NEM). These obligations include compliance with the *National Electricity Law and National Electricity Rules*, and policies and procedures developed by the Australian Energy Market Operator (AEMO), *Electricity Metering Code*, including business-to-business (B2B) obligations and procedures, metrology procedures, and other rules and directions. These obligations drive capital and operating costs.
- Corporate obligations—these are associated with running a large and complex business in Australia, which has significant economic, environmental, employment, and safety impacts on the community. These obligations relate to finance and taxation, intellectual property, human resources, terrorism and criminal matters, and ensuring appropriate compliance systems, internal auditing and due diligence procedures are in place. Relevant acts include the *Annual Reports (Government Agencies) Act 2004 (ACT)*, *Taxation (Government Business Enterprises) Act 2003 (ACT)*, *Corporations Act 2001 (Cwth)* and the *Privacy Act 1988 (Cwth)*. These obligations give rise to capital and operating costs.

1.2 Consumer engagement

The Rules require the AER to have regard to the extent to which ActewAGL Distribution's operating and capital expenditure forecasts include expenditure to address the concerns of electricity consumers as identified in the course of its engagement with them.[6] ActewAGL Distribution's regulatory proposal details the activities undertaken to engage with consumers thus far and its consumer engagement strategy going forward.

1.2.1 AER's views on effectiveness of ActewAGL's consumer engagement

In Section 10 of the draft decision overview the AER expresses its views on the effectiveness of ActewAGL Distribution's consumer engagement, which is summarised as follows:

> *While acknowledging efforts from ActewAGL to improve its engagement with its consumers, we consider that ActewAGL has significant work to do to give consumers more say in the services it*

[6] *National Electricity Rules*, clause 6.5.6(e)(5A) and clause 6.5.7(e)(5A)

provides. We base this view on stakeholder submissions and from our own observations of the engagement activities ActewAGL undertook.

We consider that:

- *willingness to pay studies are useful tools but do not on their own satisfy obligations to engage with consumers*
- *there are gaps in the types of customers that ActewAGL has engaged with*
- *ActewAGL's focus on future engagement does not satisfy its obligations under the capex and opex criteria.*

Further, our guideline expects engagement will flow both ways and not be limited to providing information to customers.[7]

In claiming that it has had regard to the extent to which ActewAGL Distribution's operating expenditure (opex) and capital expenditure (capex) proposals include expenditure to address consumer concerns, the AER points to detail of its assessment of these factors in the respective opex and capex attachments. However, the extent of the detail of AER's assessment is to state that for capex:

We have had regard to the extent to which ActewAGL's proposed total forecast capex includes expenditure to address consumer concerns that have been identified by ActewAGL. On the information available to us, including submissions received from stakeholders, we have been unable to identify the extent to which ActewAGL's proposed total forecast capex includes capex that address the concerns of its consumers that it has identified.[8]

And for opex:

We understand the intention of this particular factor is to require us to have regard to the extent to which service providers have engaged with consumers in preparing their regulatory proposals, such that they factor in the needs of consumers.

We have considered the concerns of electricity consumers as identified by ActewAGL in assessing its proposal.[9]

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[7] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Overview*, November, page 65

[8] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 6: Capital expenditure*, November, page 6-29

[9] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, pages 7-22 and 7-23

ActewAGL Distribution does not consider this to be adequate detail to understand how the AER has assessed the extent to which ActewAGL Distribution's expenditure proposals have addressed consumer concerns, or the AER's own consideration of the concerns of consumers in making substitute forecasts. As such, ActewAGL Distribution relies on the views expressed in Section 10 of the draft decision overview in understanding how the AER has had regard to ActewAGL Distribution's consumer engagement in making its draft decision.

1.2.2 Willingness to pay studies

The AER notes that a number of concerns were raised by stakeholders about how the study was conducted, for example the types of questions which were asked.[10] All three of the studies of willingness to pay in the ACT employ the choice modelling survey technique.

By their very nature, choice modelling questions are neutral. They allow respondents to express, through their choices, the trade-off between price and service that they are willing to make. While the researcher specifies the price-service alternatives that are presented in each question, it is not possible to manipulate the questions to force respondents into expressing a higher willingness to pay (or lower willingness to accept). If the researcher presents alternatives that result in respondents always choosing the lowest-cost alternative or always choosing the highest-service alternative, then it will not be possible to estimate a statistically significant trade-off between price and service (that is, willingness to pay or accept).

Therefore, on the basis of focus group discussion and pilot surveys, the analyst must tailor the alternatives to account for consumer preferences. This process took place in the studies conducted in the ACT, which is demonstrated by the high levels of statistical significance obtained in the models estimated as part of the studies. ActewAGL Distribution also notes that the surveys were developed in consultation with consumer focus groups and in-depth interviews with consumers and were further refined based on feedback from respondents in pilot surveys.

All three studies have been subject to review by leading authorities in the field of consumer preference valuation. The 2003 study was overseen by Professor Ken Train, with peer review by Professor David Hensher. The 2009 study was overseen by Professor Jeff Bennett and Professor David Hensher, with input from Professor Peter Abelson and Professor John Rose and review from Professor Wiktor Adamowicz and Professor Riccardo Scarpa. The 2012 study was overseen by Professor Michael Ward, with peer review from Professor Riccardo Scarpa. The 2003 and 2009 studies have been subject to the further scrutiny of referees for academic journals.

[10] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Overview*, November, page 67

The 2009 and 2012 studies were undertaken by researchers at the Australian National University (ANU) and the University of Sydney, not as part of consultancies for ActewAGL Distribution, but as independent research projects funded in part by grants from ActewAGL Distribution. As part of the university oversight, both projects were subject to the ANU ethics committee approval process. Participants in the research were provided with contact details for the ethics committee to voice any concerns with regard to the ethical conduct of the studies. This process fed back into the conduct of the research, with researchers involved in the 2009 study making a minor revision to the survey instrument early in the fieldwork period in consultation with the ethics committee.

The AER states that it considers that ActewAGL Distribution could be more transparent about how these studies have been conducted.[11] As a result of the involvement of academic researchers in the willingness to pay studies undertaken in the ACT and the significant contribution that the research represents to the international body of evidence in this emerging field, the primary avenue for publication of the methods, results and findings of the studies has been articles in peer-reviewed academic journals. Articles currently published include:

- McNair B.J. and Abelson P., 2010. Estimating the Value of Undergrounding Electricity and Telecommunications Networks. *The Australian Economic Review* 43, 376-388. (Attachment G7)
- McNair B.J., Bennett J. and Hensher D.A., 2011. A Comparison of Responses to Single and Repeated Discrete Choice Questions. *Resource and Energy Economics* 33, 544-571. (Attachment G8)
- McNair B.J., Bennett J., Hensher D.A. and Rose J.M., 2011. Households' Willingness to Pay for Overhead-to-Underground Conversion of Electricity Distribution Networks. *Energy Policy* 39, 2560-2567. (Attachment G9)
- McNair B.J., Hensher D.A. and Bennett J., 2012. Modelling Heterogeneity in Response Behaviour Towards a Sequence of Discrete Choice Questions: A Probabilistic Decision Process Model. *Environmental and Resource Economics* 51, 599-616. (Attachment G10)
- Hensher D.A., Shore N. and Train K., 2014. Willingness to pay for residential electricity supply quality and reliability. *Applied Energy* 115, 280–292. (Attachment G12)

Further articles are expected to follow, particularly in relation to the most recent study in 2012.

[11] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Overview*, November, page 67

However, in response to the AER’s comments and to ensure there is no question over transparency, ActewAGL Distribution also attaches to this revised regulatory proposal the reports that were prepared for ActewAGL Distribution as part of these studies at Attachment G6 and Attachment G11.

In relation to the AER’s reference to a number of stakeholder comments relating to the question of whether customers would prefer lower service levels in return for lower prices, ActewAGL Distribution notes that regulatory obligations in relation to service levels is not a constituent decision in ActewAGL Distribution’s distribution determination. The expenditure objectives in Clauses 6.5.6(a) and 6.5.7(a) of the Rules require expenditure forecasts to be set based on regulatory requirements or, if there are no relevant regulatory requirements, based on maintaining service levels. ActewAGL Distribution’s regulatory obligations in relation to network reliability, for example, are set by the ACT in the Supply Standards Code made under the *Utilities Act 2000*.[12] The AER does set performance targets as part of the STPIS, but these must also have regard to regulatory obligations under Clause 6.2.2(b)(3)(ii).

The AER states its view that the conclusions from ActewAGL Distribution’s willingness to pay studies are not consistent with the findings of the New South Wales and Queensland governments or with AEMO’s recent willingness to pay studies.[13] The implication of the AER’s statement is that ActewAGL Distribution’s results represent an outlier relative to these other studies. This is not the case. The results obtained in relation to the value placed on reliability in the ACT lie within the range of values estimated in the studies cited by the AER. The New South Wales study undertaken by the AEMC that is cited by the AER estimated value of customer reliability (VCR) at $95/kWh (in $2011-12),[14] which is significantly higher than the VCR estimate proposed by ActewAGL Distribution in its regulatory proposal of $67/kWh (in $2014-15).[15] The AEMO study cited by the AER, in contrast, found a VCR for New South Wales of $38/kWh (in $2014-15)[16] that is lower than ActewAGL Distribution’s proposed VCR. ActewAGL Distribution

[12] Utilities (Electricity Distribution Supply Standards Code) Determination 2013, Disallowable Instrument DI2013–221, made under the Utilities Act 2000, section 65 (application of industry code provisions)

[13] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Overview*, November, page 67

[14] See Attachment G16, AEMC, 2012, *Final Report – NSW Workstream, Review of Distribution Reliability Outcomes and Standards*, August

[15] ActewAGL, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period*, *Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), page 374

[16] See Attachment G17, AEMO, 2014, *Value of customer reliability review*, Final Report, September

notes that the VCR in the AER's current STPIS guideline of around $56/kWh (in $2014-15) is reasonably close to ActewAGL Distribution's proposed VCR, in light of the range of results from other studies. Regardless, as discussed in ActewAGL Distribution's submission to AEMO in relation to its draft application guide, there are reasons to expect that VCR may be higher for ACT than for NSW, including colder winters and higher average income.[17]

With respect to the findings of the New South Wales and Queensland reviews in relation to whether there would be net benefits from adjusting service standards in those jurisdictions, there is no reason to expect that similar findings should be reached for the ACT. The net benefits of changes in reliability depend both on the marginal cost (or cost saving) of reliability improvement (or degradation) and on the willingness to pay (or accept compensation) for reliability improvement (or degradation). These values will vary across locations depending on numerous factors, including existing network assets and their configurations, prices, consumer wealth, and climate. The Ministerial Council on Energy has stated that "*it is entirely appropriate for standards to differ across jurisdictions due to the different characteristics of distribution networks*."[18] The AEMC noted and agreed with this statement in its Issues Paper for its review of national reliability outcomes and standards.[19]

The AER states its view that willingness to pay studies alone do not satisfy ActewAGL Distribution's consumer engagement obligations. ActewAGL Distribution notes that its consumer engagement program outlines a number of activities including regular meetings of the Energy Consumer Reference Council (ECRC), large customer and retailer interviews, focus groups, website interaction and public forums. ActewAGL Distribution considers these activities in addition to willingness to pay studies satisfy its obligations to engage with consumers. ActewAGL Distribution is committed to continuing and strengthening its consumer engagement activities, and will monitor these activities to ensure that they remain transparent and open to customers.

1.2.3 Timing and description of proposed engagement

As stated in the subsequent regulatory proposal, ActewAGL Distribution has developed a consumer engagement framework which reflects the principles contained in the AER's consumer engagement guidelines. The framework sets out our existing engagement activities, and includes

[17] See Attachment G18, ActewAGL, 2014, *Submission on Value of customer reliability - Response to Application Guide Draft Report*, November

[18] See Attachment G19, Ministerial Council on Energy, 2011, *Terms of reference Australian Energy Market Commission Review of distribution reliability outcomes and standards*, August, page 3

[19] See Attachment G20, AEMC, 2012, *Issues Paper – National Workstream, Review of distribution reliability outcomes and standards*, June, page 40

a plan for further embedding consumer engagement in the business such that genuine and meaningful consumer engagement becomes part of business-as-usual processes. ActewAGL Distribution is of the view that achievement of this is an evolving process over a number of years.

The AER's draft decision considers ActewAGL Distribution's consumer engagement program was lacking in detail.[20] Figure 1.1. ActewAGL Distribution consumer engagement activities 2014/15

provides a timeline of programed consumer engagement activities for 2014/15 as they relate to the regulatory program. As acknowledged by the AER, ActewAGL Distribution has only had a short amount of time to implement the AER's consumer engagement timeline for network service providers following the release of the consumer engagement guideline in November 2013, even though consultation prior to the first submission would have been preferred by stakeholders. [21] Expenditure on a dedicated consumer engagement program was also not incorporated in the current regulatory period.

The program of consultation to 30 June 2015 includes:

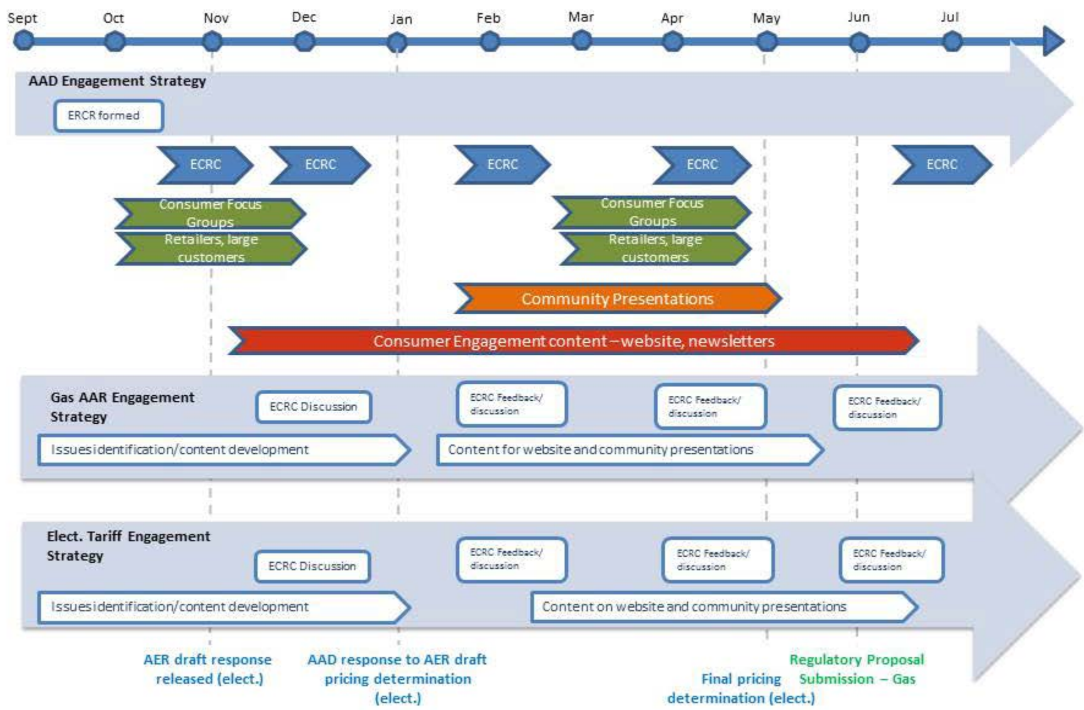
- Continued meetings of the ECRC
- Large customer and retailer interviews
- Focus groups
- Website interaction
- Public forums as appropriate.

This consultation will primarily focus on the strategic review of electricity tariffs and upcoming gas determination as a more appropriate use of consumer time and energy at this stage of the electricity determination process.

[20] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Overview*, November, page 68

[21] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Overview*, November, page 25

Figure 1.1. ActewAGL Distribution consumer engagement activities 2014/15



1.2.4 ActewAGL Distribution's consumer engagement strategy

The AER's draft decision notes comments from the Consumer Challenge Panel (CCP) and other stakeholders that ActewAGL Distribution's consumer engagement program does not represent a significant cross-section of ActewAGL Distribution's customers.[22] However, ActewAGL Distribution undertook stakeholder analysis during the preparation of its consumer engagement strategy to ensure this was not the case. During this process the following cohort consumer groups were identified:

- ACT and NSW residents – the families and households that access energy provided through our distribution networks.

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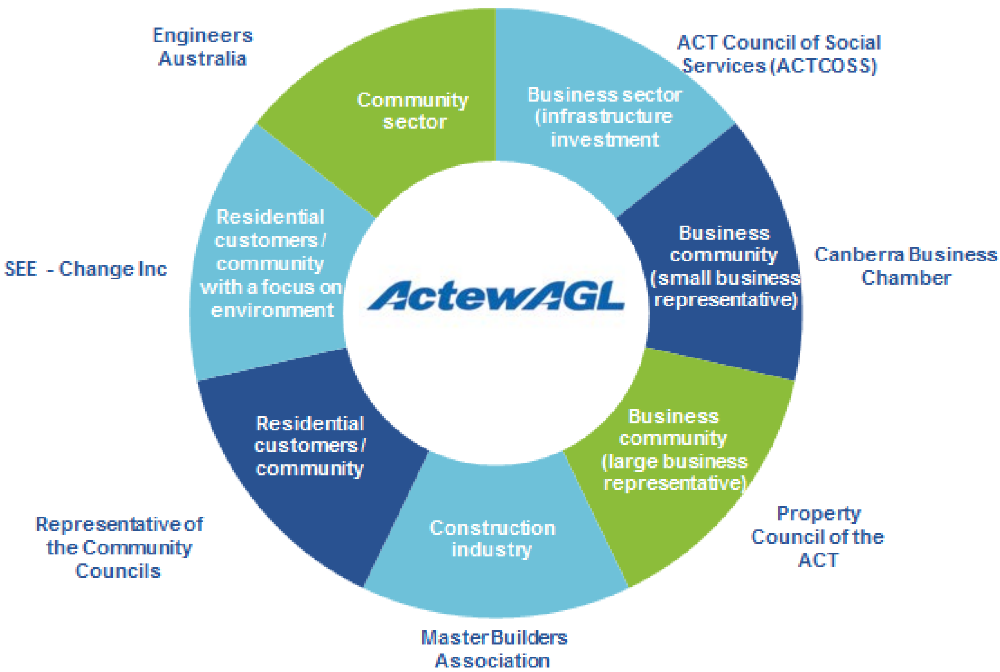
[22] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Overview*, November, page 68

- Large and or critical customers – those customers that access large amounts of energy, have more than standard infrastructure or have specialist service delivery needs such as hospitals.
- Commercial business owners – businesses of all sizes that access energy through our network, or provide goods and services associated in relation our network.
- Land and property developers – through the creation of new network infrastructure to service their developments.

For each of these cohort groups peak bodies were approached and discussions occurred about the best way to engage with this cohort. In the ACT there are well developed representative bodies such as the seven geographically focused ACT Community Councils, which provide two-way forums for providing information to the community and gaining feedback directly from community members, as well as membership based organisations such as SEE-Change and the ACT Council of Social Services (ACTCOSS).

In the first instance representatives of each stakeholder group were invited to participate in the ECRC. The ECRC has been tasked with considering what other cohorts of consumer groups should be considered and involved in the ECRC, or what sub-groups may exist within the cohort groups identified above. Figure 1.2 shows the consumer cohorts and how they are represented on the ECRC.

Figure 1.2. Consumer cohort representatives on the ECRC



The following additional cohort groups have been identified and at this stage are not involved with the ECRC. Particular strategies to establish engagement frameworks and a better understanding of the priorities of these cohort groups are being developed.

- Retailers – retailers registered in the ACT market.
- Embedded generators – Large Scale embedded generators (>5MW registered with AEMO) and Small Scale embedded generators (<5MW) connected to our system.

Consultation with consumers to date has consisted of preliminary focus group work and an initial inception meeting of the ECRC has been held to better understand the priorities of these cohort groups. To date, a number of key activities outlined in ActewAGL Distribution's consumer engagement strategy have been undertaken:

- The ECRC has been established. Members have discussed the AER's draft decision and expressed interest in being actively engaged in the development of the gas access arrangement proposal during 2015.
- Consumer focus groups have been hosted considering the following topics:
  - Tariff options and preferences
  - Impacts of new technologies
  - Smart metering
  - Capacity building and long-term infrastructure
- A six month program of consumer engagement and key issues has been developed (for both electricity and gas) to be implemented during 2015.
- A program to refresh the ActewAGL Distribution website is underway with a consumer engagement focus, including specific content on engagement activities and a two-way feedback forum to allow consumers to contribute more directly to discussions around key consumer issues. Initial information including the consumer engagement strategy and information on the ECRC are already available on the website.

Over the next 6 to 12 months, ActewAGL Distribution's consumer engagement strategy will allow meaningful and active consumer engagement in the work of ActewAGL Distribution, including discussions about cost of trade-offs, better understanding of consumer needs and options within the regulatory framework and tariffs structures to better meet the needs of individual consumer cohorts.

The ECRC will provide the primary focus for gathering and reporting on the concerns and expectation of these consumer cohorts. Early discussions of the ECRC have focussed on the best way to maintain strong communications with the broader consumer base through the representatives on the ECRC. At the suggestion of the ECRC members, a communique is issued after each ECRC meeting as a tool for consumer representatives to communicate back to their constituents and seek input and comments. The ECRC will meet monthly during 2015, with a view to meet quarterly and as needed beyond this time.

Other consumer engagement activities such as focus groups, customer surveys, presentations and conversations with cohort groups and major customers, and public forums will be undertaken over the regulatory period. The outcomes of these activities will be feed directly into the ECRC, who will also contribute to identification of appropriate key performance indicators. Regular reporting from the ECRC will be direct to senior management and the CEO and through these channels will be fed into the relevant operational areas of the business, or into planning for regulatory submissions as appropriate. Additionally, ActewAGL Distribution will implement staff training to move towards a more customer centric organisational culture.

1.3 Structure of the revised regulatory proposal

The Executive Summary and Overview preceding this introduction provides a summary of the revised regulatory proposal. It includes:

- A summary of ActewAGL Distribution's key contentions in support of its rejection of several of the AER's draft constituent decisions.
- A summary comparison of the ActewAGL Distribution's regulatory proposal, the AER's draft decision, and ActewAGL's Distribution's revised regulatory proposal, as well as an explanation for any material differences between the ActewAGL Distribution regulatory proposal and revised regulatory proposal.

Following this introductory chapter:

- Chapter 2 advances broad contentions that transcend constituent decisions and show that the AER's draft decision, far from being the NEO preferable decision, would be detrimental to the achievement of the NEO and that a distribution determination on the basis of ActewAGL Distribution's revised regulatory proposal would be likely to contribute to the achievement of the NEO to the greatest degree and is materially preferable to the draft decision in making a contribution to the NEO.
- Chapter 3 responds to the AER's detailed analysis of ActewAGL Distribution's base opex, the opex rate of change, the step change adjustments to base opex, the forecasting methodology for determining the opex forecast for the 2014-19 period, and addresses the imperative for establishment of a transition path, in the event that the AER is minded to make a final decision on opex that is substantively similar to its draft decision.
- Chapter 4 responds to each of the AER's key concerns with ActewAGL Distribution's proposed capex program**:** ActewAGL Distribution demonstrates that it undertook a top-down, holistic assessment; ActewAGL Distribution's augmentation capex is not

overstated, but rather is necessary to achieve the capex objectives specified in the Rules; ActewAGL Distribution's replacement capex is not overstated, and the conclusions drawn by the AER from its historical trend analysis and comparative benchmarking analysis is flawed; the AER's alternative estimate for repex is based on incorrect data and flawed analysis and is therefore invalid; the AER's capitalised overhead 'adjustment factor' is inconsistent with ActewAGL Distribution's revised cost allocation method (CAM) that applies from 1 July 2014; ActewAGL Distribution's capex forecasts should be based on its proposed revised labour and material escalators.

- Chapter 5 updates ActewAGL Distribution's demand forecasts for use by the AER in its final decision using the method utilised in its regulatory proposal for the subsequent regulatory period. ActewAGL Distribution contends that the AER errs in rejecting ActewAGL Distribution's consumption forecasts and ActewAGL Distribution maintains that its consumption forecast methodology generates appropriate inputs into the post tax revenue model (PTRM) and that the AER should accept ActewAGL Distribution's forecast consumption in its final decision.
- Chapter 6 responds to the AER's draft decision in respect of the RAB and depreciation. Although ActewAGL Distribution accepts the AER's draft decision to reduce the remaining asset life of the opening asset class, ActewAGL Distribution rejects the AER's draft decision on its closing regulatory asset base (RAB) values as at 30 June 2019 for each of distribution and transmission. ActewAGL Distribution does not accept the AER's draft decisions on forecast capex or forecast depreciation for the 2014-19 period.
- Chapter 7 responds to the AER's draft decision in respect of corporate income tax. ActewAGL Distribution rejects the AER's draft decision on the cost of corporate income tax for the 2014-19 period. In particular, while ActewAGL Distribution accepts the AER's draft decision on the standard tax asset life for the 'equity raising costs' asset class for the 2014-19 period of 5 years, it does not accept the AER's draft decisions on the value of gamma, forecast opex for the 2014-19 period or forecast capex for that period
- Chapter 8 sets out ActewAGL Distribution's response to the AER's draft decision in relation to the return on capital, gamma, equity and debt raising costs, and forecast inflation. ActewAGL Distribution considers that the method adopted by the AER in its draft decision will not result in a return on equity that is consistent with the rate of return objective. ActewAGL Distribution considers that the method adopted by the AER in its draft decision will not result in a return on debt that is consistent with the rate of return objective. ActewAGL Distribution maintains its position, as supported by the evidence attached as part of its regulatory proposal that gamma should be 0.25. ActewAGL Distribution contends that the AER should allow for its proposed liquidity costs and three month ahead financing costs in relation to debt raising costs.

- Chapter 9 sets out the summation of ActewAGL Distribution's revenue requirements for distribution and transmission standard control services from the elements of the cost building blocks calculated in earlier chapters.
- Chapter 10 provides ActewAGL Distribution's proposals relating to the control mechanism and indicative prices for distribution standard control services.
- Chapter 11 responds to the AER's draft decision on the additional pass through events that are to apply for the subsequent regulatory period. ActewAGL Distribution accepts the AER's draft decision that a demand management and embedded generation connection incentive scheme (DMEGCIS) event should not apply in the subsequent regulatory period. However, ActewAGL Distribution rejects the AER's draft decision not to accept ActewAGL Distribution's proposed general pass through event and insurer credit risk event. In addition, it does not wholly accept the AER's draft decision on the definition of the insurance cap event.
- Chapter 12 responds to the AER's draft decision on the incentives schemes:
    - (a) efficiency benefit sharing scheme (EBSS);
    - (b) capital expenditure sharing scheme (CESS);
    - (c) service target performance incentive scheme (STPIS);
    - (d) demand management and embedded generation connection incentive scheme (DMIS).
- Chapter 13 responds to the AER's draft decision on the classification of distribution services.
- Chapter 14 respond to the AER's draft decision on alternative control services (metering and ancillary services). For metering, ActewAGL Distribution accepts the draft decision to apply up-front charges to recover the costs of new and upgrade meters. ActewAGL Distribution also agrees with the AER that it is appropriate to add new metering related services. However, ActewAGL Distribution proposes to introduce, for the AER's new service classifications, an exit fee that should be more broadly defined to include not only administrative costs but also residual asset values. If the AER continues to reject ActewAGL Distribution's proposal to recover residual meter asset values via an exit fee, then the new standard control service relating to residual meter values should be defined more broadly to allow recovery of fixed opex, as well as residual asset values for type 5 and type 6 meters.
- Chapter 15 sets out ActewAGL Distribution's acceptance of the AER's draft decision on the negotiating framework.

- Chapter 16 describes the revisions to ActewAGL Distribution’s proposed transmission pricing methodology , following consultation with TransGrid, to ensure that it is consistent with TransGrid’s revised transmission pricing proposal.

Detailed supporting information, as indicated in the text, is included in attachments to the proposal. The list of these attachments, which form part of the revised regulatory proposal, can be found at the end of this document.

2 The NEO preferable decision

2.1 Introduction

In its draft decision, the AER discusses how the constituent components of its decision relate to each other and concludes that the decision, as a whole, will contribute to the achievement of the NEO to the greatest degree (that is, it is the NEO preferable decision). ActewAGL Distribution rejects this conclusion.

In this Chapter 2, ActewAGL Distribution advances broad contentions that transcend constituent decisions and show that the AER's draft decision, far from being the NEO preferable decision, would be detrimental to the achievement of the NEO and that a distribution determination on the basis of ActewAGL Distribution's revised regulatory proposal would be likely to contribute to the achievement of the NEO to the greatest degree and is materially preferable to the draft decision in making a contribution to the NEO.

Section 2.2 of this Chapter sets out ActewAGL Distribution's contentions regarding the legal framework governing NEO preferable decision-making. These contentions include in particular that:

- The ultimate object of the NEL and the Rules as set out in the NEO is economic efficiency - that is, productive, allocative and dynamic efficiency - as the means by which the long term interests of consumers are promoted.
- The phrase 'long term' in the NEO requires that short-term gains in productive efficiency are not pursued at the expense of dynamic efficiency. Put another way, the NEO is concerned with the interests of consumers in sustainably low prices rather than the pursuit of short-term price reductions at the expense of their interests in the quality, safety, reliability and security of supply and the reliability, safety and security of the distribution system in the longer term.
- The RPPs can be taken to be consistent with, and do in fact promote, the NEO. Likewise, the Rules, including in particular the expenditure criteria and the other Rules governing the building blocks, can be taken to be consistent with, and do in fact promote, the NEO.
- A decision by the AER that is not in accordance with law cannot be said to contribute to the achievement of the NEO or constitute a NEO preferable decision. Rather, a decision is properly said to be a NEO preferable decision where, of the range of decisions that are in accordance with law, it is to be preferred on the basis that it makes the greatest contribution to the achievement of the NEO.
- It follows from the above propositions concerning the NEO, the RPPs and the Rules that:

- a decision that results in sustainably low prices while maintaining quality, safety, reliability and security will contribute to the achievement of the NEO and is (all else being equal) NEO preferable to a decision that pursues short-term price reductions at the expense of consumers' interests in quality, safety, reliability and security in the longer term or, put another way, short-term gains in productive efficiency at the expense of dynamic efficiency;
- a decision that is consistent with the revenue and pricing principles (RPPs) will contribute to the achievement of the NEO, and that such a decision will (all else being equal) contribute to the achievement of the NEO to a greater degree than a decision that is not consistent with one or more of the RPPs; and
- a decision that is consistent with the Rules, the scheme of those Rules and their object will contribute to the achievement of the NEO, and such a decision will (all else being equal) do so to a greater degree than one which is not consistent with the Rules, their scheme or their object.

The remaining sections of this Chapter detail ActewAGL Distribution's contentions in support of the proposition that the making of its distribution determination for the subsequent regulatory period on the basis of the draft decision would be detrimental to the achievement of the NEO and would not constitute the NEO preferable decision, rather the making of the determination on the basis of this revised regulatory proposal would be the NEO preferable decision. In summary, these contentions are as follows:

- Various elements of the draft decision are not in accordance with law which has the necessary consequence that the draft decision is not, indeed is incapable of constituting, a NEO preferable decision, whereas a final decision based on the revised regulatory proposal would be in accordance with law and thus to be preferred to the draft decision in contributing to the achievement of the NEO. This is discussed in section 2.3 below and the proposition that various elements of the draft decision are not in accordance with law (and a decision on the basis of the revised regulatory proposal, by contrast, would be) further developed in the remaining Chapters of this revised regulatory proposal.
- ActewAGL Distribution contends that:
    - the AER's primary focus on productive efficiency is not in the long term interests of consumers;
    - the primacy given by the AER to benchmarking at the expense of the other opex factors does not result in expenditure that is consistent with the NEO; and
    - there are significant broader implications of the deterministic use of benchmarking which are not in the long term interests of consumers - it can lead to error in setting the opex allowance and also increases the potential for

opex allowances that are not achievable, and which therefore does not meet the NEO.

This is discussed further in Section 2.4 below.

- The retrospective application of changes in the AER's regulatory approach effected by the draft decision will result in unanticipated and material financial losses to ActewAGL Distribution which, in turn, mean its effective expenditure allowances for the subsequent regulatory period will be significantly lower than even the AER's estimate of efficient expenditure for that period. This cannot be reconciled with the scheme of the regime, the section 7A(2) RRP or the NEO, which requires prices that support the maintenance of quality, safety, reliability and security. This is discussed further in Section 2.5 below.
- A consideration of the interrelationships between constituent components of the draft decision discloses that the various components are inconsistent with, and undermine one another, with the consequence that the draft decision detracts from, rather than contributing to, the achievement of the NEO and, thus, does not constitute a NEO preferable decision. In particular, ActewAGL Distribution contends that:
    - the AER’s draft decision on opex undermines the incentives that existed where the previous revealed cost approach to forecasting opex was adopted in combination with the application of an efficiency benefit sharing scheme (EBSS);
    - the AER’s opex and capex draft decisions are inconsistent with and undermine the service quality incentive framework (STPIS); and
    - the AER has erred in not taking into consideration the inter-relationship between its opex draft decision and its capex draft decision in setting expenditure allowances.

  This is discussed further in Section 2.6 below.
- The expenditure allowances proposed in the draft decision do not reflect a realistic expectation of the expenditure required to achieve the opex and capex objectives set out in clauses 6.5.6(a) and 6.5.7(a) respectively of the Rules and would require drastic changes to ActewAGL Distribution's business model within an injudicious period of time, with the consequence that the draft decision, if reflected in the final decision, would deliver a short-term reduction in price but would have potentially dire consequences for reliability, security and safety. Such a decision does not contribute to the achievement of the NEO and cannot be said to be NEO preferable. By contrast, ActewAGL Distribution proposes sustainable expenditure allowances, with the result that a final decision on the basis of that revised proposal would result in sustainably low prices and the maintenance of consumers’ long term interests with respect to reliability, security and safety. This is discussed further in section 2.7 below.

- ActewAGL Distribution was denied a reasonable opportunity to make submissions on the draft decision (as a consequence of the AER's failure to provide to ActewAGL Distribution all of the material on which it relies in that Decision and its delayed provision to ActewAGL Distribution of other material on which it relies) in breach of the AER's procedural obligations and this, in turn, renders it less likely that the AER's final decision will contribute to the achievement of the NEO, particularly where that final decision is based on the draft decision. This is discussed further in section 2.8 below.

Table 2.1 compares the AER's draft decisions on each of the revenue building blocks specified in clause 6.4.3 of the Rules with ActewAGL Distribution's revised proposals concerning those building blocks.

For the reasons discussed in the remaining sections of this Chapter, and further developed in the remaining Chapters of this revised regulatory proposal, the AER's draft decisions are affected by errors which render those decisions detrimental to the achievement of the NEO and, thus, not NEO preferable.

By contrast for the reasons also there discussed, ActewAGL Distribution's revised proposals, not being affected by those errors, contribute to the achievement of the NEO and are thus NEO preferable to the AER's draft decisions. It follows that Table 2.1 illustrates the relative revenue outcome of the draft decision, which does not contribute to the achievement of the NEO and is not NEO preferable, to that of a NEO preferable decision.

Table 2.1 Comparison of revenue building blocks, distribution and transmission

	ActewAGL Distribution's revised proposal 2014-19 (nominal $m)	AER's draft decision, 2014-19 (nominal $m)	Difference (nominal ($m)
Return on capital	411.3	307.4	103.9
Depreciation	180.5	177.0	3.5
Corporate income tax	55.7	35.9	19.8
Incentive scheme increments/decrements	-18.4	0	-18.4
Forecast opex	406.2	240.6	165.6
Total revenue (unsmoothed)	**1,035.3**	**760.8**	**274.5**

To facilitate this assessment, in Table 2.2 below ActewAGL Distribution summarises its contentions regarding the effect of the AER's errors in the key constituent components of the draft decision, identified in this Chapter and further developed in the remainder of this revised regulatory proposal, on the achievement of the NEO.

Table 2.2 Constituent components of the draft decision, corresponding or interrelated building block(s) affected and element of NEO achievement of which is detrimentally affected

Key constituent components of draft decision	Corresponding and/or interrelated building block(s)	Element of NEO detrimentally affected and effect of error on long term interests of consumers
1. Forecast capex	Return on capital Return of capital Tax allowance	• Efficient investment in electricity services • Efficient operation of electricity services • Safety obligations not met • Reliability standards or regulatory obligations not met • Unable to meet demand for services from existing customers and potential consumer
2. Forecast opex	Forecast opex	• Efficient investment in electricity services • Efficient operation of electricity services • Allocative efficiency is reduced due to inability to meet service standards required by consumers and/or inability to meet safety and/or other regulatory obligations
3. Allowed rate of return - Cost of debt - Cost of equity	Return on capital Return of capital Tax allowance	• Efficient investment in electricity services • Allocative efficiency is reduced; discourages ongoing investment
4. Gamma	Cost of corporate income tax	• Efficient investment in electricity services • Allocative efficiency is reduced; discourages ongoing investment
5. Incentive schemes	Carry-over amounts	• Efficient investment in electricity services • Efficient operation of electricity services
6. Consumption forecasts	Affects the allowed revenue and price path (X factors)	• Efficient investment in electricity services • Efficient operation of electricity services • Interests of consumers

As discussed in Section 2.2.4 below, ActewAGL Distribution recognises that, because it is the overall decision that must be NEO preferable, the existence of error in a decision does not, of itself, establish that the decision is not NEO preferable or that another decision is materially preferable in making a contribution to the NEO.

It is conceivable that the effect on the overall decision of two or more errors may offset one another, particularly given the interrelationships between constituent components of a distribution determination. At the same time, because of the interrelationships that exist between constituent components of a distribution determination, an error in the making of a decision may render the overall decision not NEO preferable notwithstanding that its effect on the constituent component of the decision in respect of which it is made is limited.

Against this background, ActewAGL Distribution maintains that, having regard to the nature and quantum of their effect on economic efficiency individually and as summarised in Table 2.1 and Table 2.2 above, each of the errors in the draft decision it has identified in this Chapter and further developed in the remaining Chapters of this revised regulatory proposal must be corrected to render the overall final decision of the AER NEO preferable and, if so corrected, would render the final decision materially preferable to the draft decision in making a contribution to the achievement of the NEO.

This is because the AER has not, in respect of any of the asserted errors in the draft decision, made any offsetting adjustment to interrelated constituent components of its draft decision. Rather, in making each and every one of the constituent components of the draft decision, the AER has (in contradistinction to the NEO) sought to promote the short-term interests of existing consumers, rather than the long-term interests of existing and potential consumers, at the expense of dynamic efficiency.

If the AER’s draft decision were to be implemented, the adjustment to first year prices (the P_0 adjustment) would be 29 per cent.[23] There is no underlying economic justification for a price adjustment of this magnitude. It is explicable only as a short-term, 'knee jerk' response to consumer concerns regarding rising electricity prices. The analysis presented in this Chapter and summarised in Table 2.1 and Table 2.2 above concerning the errors in the AER's draft decision, their effects individually and collectively on the achievement of the NEO and the quantum of those effects discloses that ActewAGL Distribution’s revised regulatory proposal contributes to the achievement of the NEO and is materially preferable to the AER’s draft decision in making a contribution to the NEO.

[23] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Overview*, November, page 31

2.2 The relevant legal framework for NEO preferable decision-making

2.2.1 The NEO

The NEO is set out in section 7 of the NEL and reads as follows:

> ***7—National electricity objective***
>
> *The objective of this Law 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-*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system.*

The ultimate objective of the regulatory regime established by the NEL and Rules is thus economic efficiency, including efficient investment in the system with which the provider provides services, as the means by which the long term interests of consumers are promoted. In its Decision paper on the review of the merits review regime under the NEL, the Standing Council on Energy and Resources (SCER, now COAG Energy Council) correctly articulated the position as follows:[24]

> *The key objective of the national regulatory frameworks governing both electricity and gas in Australia is to promote the long term interests of energy consumers, as set out in the National Electricity Objective (NEO) and the National Gas Objectives (NGO). This is delivered through efficient investment in (that is, ensuring required investment represents the best value for consumers over the long term, taking into account cost, timing, quality, safety, reliability and security of supply), operation and use of energy infrastructure.*

Economic concept of efficiency

That the NEO is concerned with the economic concept of efficiency is apparent from the second reading speech for the Bill to introduce the new NEL and, in so doing, the NEO:[25]

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[24] SCER 2013, *Regulation Impact Statement Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks Decision Paper*, 6 June 2013, p. 1. This has also been recognised by the Australian Competition Tribunal in similar terms. See, for example, *Application by Energy Australia and Others (including corrigendum dated 1 December 2009)* [2009] ACompT 8, at [79]-[81], including in particular the Tribunal's observation at [81] that the achievement of the efficiency objectives is the very purpose of the regulatory regime.

[25] House of Assembly Hansard, 9 February 2005, Second reading speech for the *National Electricity (South Australia) (New National Electricity Law) Amendment Bill 2005*, p. 1452. Section 3 of the NEL provides that

The market objective is an economic concept and should be interpreted as such. For example, investment in and use of electricity services will be efficient when services are supplied in the long run at least cost, resources including infrastructure are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs and productive opportunities. The long term interest of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the National Electricity Market is efficient in an economic sense the long term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised.

The concept of economic efficiency encompasses different dimensions: productive, allocative and dynamic efficiency, all of which are of relevance to the NEO.

Productive efficiency is achieved where individual firms produce the goods and services that they offer at least cost. The reference to efficient "investment in" and "operation of" electricity services in the NEO refers to productive efficiency, which can be achieved by using the least cost *combination* of both capital and operating inputs.

Allocative efficiency is achieved where the prices of resources reflect their underlying costs so that resources are then allocated to their highest valued uses (i.e., those that provide the greatest benefit relative to costs). The reference to efficient "use of" electricity services in the NEO refers to allocative efficiency. That is, the NEO will be promoted if decisions are made that result in a level and structure of prices that enables cost recovery and maximises consumer utility.

Dynamic efficiency reflects the need for industries to make timely changes to technology and products in response to changes in consumer tastes and in productive opportunities. The reference to "efficient investment" for the "long term interests of consumers" refers to dynamic efficiency. That is, the NEO will be promoted if decisions are made that give lesser weight to near-term efficiency gains and greater weight to long term productive and allocative efficiency considerations.

Schedule 2 to the NEL applies to the interpretation of the NEL. Clause 7 of Schedule 2 to the NEL provides that the interpretation of a provision of the NEL that will best achieve the purpose or object of the NEL is to be preferred to any other interpretation. Clause 8(2) of Schedule 2 to the NEL provides that, in the interpretation of a NEL provision, consideration may be given to 'Law extrinsic material' to provide an interpretation of an ambiguous or obscure provision, provide an interpretation that avoids a manifestly absurd or unreasonable result if the ordinary meaning leads to such a result or confirm the interpretation conveyed by the ordinary meaning of the provision. Clause 8(1) defines "Law extrinsic material" to mean "relevant material not forming part of this Law" and to include "the speech made to the Legislative Council or House of Assembly of South Australia by the member in moving a motion that the Bill be read a second time".

As a result, a regulatory decision requires trade-offs between competing objectives. A decision to force substantial price decreases may increase short term allocative efficiency but it has the potential to risk sustainable operations and investment plans and therefore to detrimentally impact dynamic efficiency. The NEO provides guidance on how these trade-offs should be resolved in specifying that the interests of consumers with which it is concerned are their interests in the "long term".

Long term interests of consumers

The interests of consumers of electricity with which the NEO is concerned are those in obtaining lower prices (than would otherwise be the case), increased quality, safety, reliability and security of supply and the increased reliability, safety and security of the national electricity system.[26]

The phrase 'long term' is concerned with the period over which the full effects of the AER's decision will be felt.[27] The comments of the Australian Competition Tribunal (Tribunal) on the phrase 'long term' in considering the objective of Part XIC of the *Trade Practices Act 1974* (Cth) (TPA) (now the *Competition and Consumer Act 2010* (Cth) (CCA)), being the 'long term interests of end-users', are apposite. It relevantly observed:[28]

> *In considering how these elements may combine, it may be the case, for example, that very low prices are in the short-term interests of end-users. Over the long-term, however, sustainably low prices (which may be higher than the "very low prices" referred to above) are more likely to enhance their interests, as the long-term interests of end-users are likely to suffer in an environment characterised by short-lived operators who fall over soon after the customer signs with them, as distinct from one in which reliable service-providers offer competitive, but sustainable, services. Moves that enhance the quality and diversity of service may be subject to a similar analysis.*

The NEO is, thus, concerned with the long term interests of consumers in sustainably low prices, and the maintenance or enhancement of quality, safety, reliability and security, rather than the

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[26] *Re Seven Network Limited (No 4)* (2004) ACompT 11 at [120], in discussing the objective of Part XIC of the *Trade Practices Act 1974* (Cth) (now the *Competition and Consumer Act 2010* (Cth)), being the long term interests of end-users', on which the NEO was modelled.

[27] *Re Seven Network Limited (No 4)* (2004) ACompT 11 at [120]; *Application by Chime Communications Pty Ltd (No 2)* [2009] ACompT 2 at [15], in discussing the objective of Part XIC of the TPA (now the CCA), being the long term interests of end-users', on which the NEO was modelled.

[28] *Re Seven Network Limited (No 4)* (2004) ACompT 11 at [121]

pursuit of price reductions in the short-term at the expense of their other interests. This has been recognised by the Tribunal in the following terms:[29]

> *As notes at the outset, customers will benefit in the long run if resources are used efficiently, ie if investors receive a return on efficient investment which covers the opportunity cost of the capital required to deliver the services. While consumers might benefit today from the lowest possible prices which do not provide an adequate return on investment, such prices are not in their long term interests… If those prices were sustained, they would not generally support the allocation of sufficient resources including capital, to maintain and increase the supply of the affected service in accordance with the value the consumers place on it. This would be contrary to the promotion of efficient investment and the long term interests of consumers.*

ActewAGL Distribution further observes that the NEO refers to the long term interest of “consumers”, rather than customers. This expression, together with the phrase "long term", suggests that the NEO is properly construed as concerned with the interests of actual and potential consumers of electricity, rather than existing customers of the suppliers of electricity services.

Conclusion

It is accepted by the Tribunal that the long term interests of consumers set out in the NEO requires prices to reflect the long run cost of supply and to support efficient investment by providing investors with a return which covers the opportunity cost of capital required to deliver the relevant services.[30] Similarly, in its decision paper on the review of the merits review regime under the NEL, the SCER observed that:[31]

> *The long term interests of consumers are delivered through the timely investment in energy assets to meet quality, safety or reliability requirements, and to deliver secure supplies of energy. … In its economic regulation of network service providers rule change determination, the AEMC noted that efficient investment requires:*
>
> - *there being a level of investment in network infrastructure so that safety and reliability standards are met in circumstances where consumers pay no more than is necessary for the network services they receive;*

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[29] *Re Application by ElectraNet Pty Limited (No 3)* [2008] ACompT 3 at [251]

[30] See, for example: *Re Application by ElectraNet Pty Limited (No 3)* [2008] ACompT 3 at [15]; *Application by Energy Australia and Others* [2009] ACompT 8 at [18]

[31] SCER 2013, *Regulation Impact Statement Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks Decision Paper*, 6 June 2013, p. 28

- *the costs network businesses incur in providing network services to their customers reflecting efficient financing costs. This is to allow those businesses an opportunity to attract sufficient funds for investment while minimising the resultant costs that are borne by consumers;*
- *the establishment of a certain, robust and transparent regulatory environment. Investors will have more confidence and may be more likely to invest in monopoly infrastructure where the regulatory process is certain and robust, with appropriate checks and balances in place. Consumers will also have more confidence that the outcomes are better in such an environment; and*
- *regulatory certainty in the application of the improved and strengthened rules.*[32]

The AEMC has also recognised that any change in the level of network investment is likely to impact the price, quality, reliability and security of supply of electricity to consumers.[33]

2.2.2 The revenue and pricing principles

The RPPs in section 7A can be taken to be consistent with and to promote the objectives in section 7. The principles are themselves stated normatively in the form of what is intended to be achieved.[34]

The RPPs are set out in section 7A of the NEL and relevantly include:

7A—Revenue and pricing principles

(1) The revenue and pricing principles are the principles set out in subsections (2) to (7).

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

(a) providing direct control network services; and

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[32] AEMC, 2012. *Rule determinations: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012* p 8.

[33] AEMC 2012, *Rule Determination National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012*, 2 August 2012, p. 13, where the AEMC expressly recognised that: *"Generally, any change in the level of investment in networks is likely to impact the price, quality, reliability and security of supply of electricity."*

[34] *Application by Energy Australia and Others* [2009] ACompT 8 (with Corrigendum) at [79]

(b) *complying with a regulatory obligation or requirement or making a regulatory payment.*

(3) *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—*

(a) *efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and*

(b) *the efficient provision of electricity network services; and*

(c) *the efficient use of the distribution system or transmission system with which the operator provides direct control network services.*

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

(a) *in any previous—*

(i) *as the case requires, distribution determination or transmission determination; or*

(ii) *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*

(b) *in the Rules.*

(5) *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.*

(6) *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.*

(7) *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.*

The Tribunal has had cause to consider the first of these principles and has stated as follows with respect to the intent and operation of that RPP:[35]

> *It might be asked why the NEL principles require that the regulated NSP be provided with the opportunity to recover at least its efficient costs. Why 'at least'? The issue of opportunity is critical to the answer. The regulatory framework does not guarantee recovery of costs, efficient or otherwise. Many events and circumstances, all characterized by various uncertainties, intervene between the ex ante regulatory setting of prices and the ex post assessment of whether costs were recovered. But if, as it were, the dice are loaded against the NSP at the outset by the regulator not providing the opportunity for it to recover its efficient costs (eg, by making insufficient provision for its operating costs or its cost of capital), then the NSP will not have the incentives to achieve the efficiency objectives, the achievement of which is the purpose of the regulatory regime.*
>
> *Thus, given that the regulatory setting of prices is determined prior to ascertaining the actual operating environment that will prevail during the regulatory control period, the regulatory framework may be said to err on the side of allowing at least the recovery of efficient costs. This is in the context of no adjustment generally being made after the event for changed circumstances.*

2.2.3 The Rules

Chapter 6 of the Rules contains detailed prescription as to the making of a distribution determination by the AER. In particular, Chapter 6:

- specifies the constituent decisions on which a distribution determination is predicated;
- prescribes the use of a building block approach for the determination of allowed revenues; and
- contains detailed prescription of the manner in which the AER is to:
    - determine the various building blocks including forecasts of opex and capex, the RAB, the return on capital, the estimated cost of corporate income tax and forecast depreciation; and
    - make its other constituent decisions including those with respect to incentives schemes, the X factor and the additional pass through events to be specified in the distribution determination.

[35] *Application by Energy Australia and Others* [2009] ACompT 8 (with Corrigendum) at [81]-[82]

It must be assumed that the Rules with respect to the making of a distribution determination are intended to contribute to the achievement of the NEO and are consistent with the RPPs. The reasonableness of such an assumption is underlined by the role of the NEO and the RPPs in the making of the Rules. In particular, the AEMC may only make a Rule if it is satisfied that to do so will or is likely to contribute to the achievement of the NEO[36] and, in making a Rule with respect to distribution system revenue and pricing or the regulatory economic methodologies to be applied by the AER in making or amending a distribution determination, must also take into account the RPPs.[37] Further, it may make a Rule that is different to a market initiated Rule if it is satisfied that that Rule will or is likely to better contribute to the achievement of the NEO.[38]

The building block approach to determining revenue allowances for a distribution determination, specified in clause 6.4.3 of the Rules, in particular, is constructed to ensure recovery by DNSPs of at least efficiently and prudently incurred costs, facilitating ongoing investment and promoting dynamic efficiency. Furthermore, each element of the building block is predicated, through constituent elements of the Rules, on costs that are at least efficient and prudent.

The opex and capex criteria set out in clauses 6.5.6(c) and 6.5.7(c) of the Rules, for example, are designed to ensure the expenditure allowances decided in a distribution determination reflect the efficient long run costs of achieving the opex and capex objectives set out in clauses 6.5.6(a) and 6.5.7(a) of the Rules, which in turn echo the interests of consumers of electricity with which the NEO is concerned, specifically the maintenance of quality, safety, reliability and security of supply and the reliability, safety and security of the national electricity system.

In so doing, Chapter 6 of the Rules ensures prices:

- provide a DNSP with a reasonable opportunity to recover at least its efficient costs, consistent with the RPP set out in section 7A(2) of the NEL; and
- reflect the long run costs of supply and support efficient investment by providing investors with a return which covers the opportunity cost of capital required to deliver the relevant services, a result that, as discussed in section 2.2.1 above, the Tribunal and policy-makers have recognised is serves the long term interests of consumers referred to in the NEO.

The manner in which the opex and capex objectives and criteria set out in clauses 6.5.6 and 6.5.7 of the Rules contribute to the achievement of the economic efficiency with which the NEO is

[36] Section 88(1) of the NEL

[37] Section 88B of the NEL, and items 25 to 26J of Schedule 1 to the NEL

[38] Section 91A of the NEL

concerned has been recognised by economic experts in reports prepared for, and submitted to the AER by, other network service providers appearing before it. In its report for Ausgrid on the economic interpretation of clauses 6.5.6 and 6.5.7 of the Rules, for example, NERA relevantly concluded:[39]

> *The construction of the expenditure assessment clauses 6.5.6 and 6.5.7 of the NER reflects the dimensions of efficiency discussed in the previous section. Clauses 6.5.6(a) and 6.5.7(a) provide a set of expenditure objectives, which effectively define the outputs (or the process and principles for determining the outputs) that a DNSP is required to produce. The effect of these objectives is to establish the services to be produced by DNSPs, with the implication that the Ministerial Council on Energy (MCE) intended these to reflect the desired outcomes or benefits to society. In other words, clauses 6.5.6(a) and 6.5.7(a) effectively determine the parameters of allocative efficiency for the DNSPs.*
>
> *Clauses 6.5.6(c) and 6.5.7(c) then set out the criteria to be adopted by the AER in determining whether the DNSP is proposing to produce the required goods and services in a productively efficient way, ie, whether the costs are efficient and are the costs that a prudent operator would require to achieve the expenditure objectives. The evaluation of costs in these clauses is not limited to current costs, and so is also able to encompass a longer-term view of efficiency over time, ie, dynamic efficiency.*

Similar views have been expressed by economic experts in respect of the National Gas Objective (NGO) in reports prepared for ATCO Gas Australia[40] and Jemena Gas Networks (NSW) Ltd.[41] While these reports considers the NGO and were prepared, and provided to the AER, in the context of decision-making processes under the National Gas Law (NGL) and National Gas Rules (NGR), the conclusions reached are equally applicable here because, as the AER's own advisors have recognised:[42]

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[39] Attachment B1, NERA 2014, *Economic Interpretation of Clauses 6.5.6 and 6.5.7 of the National Electricity Rules,* Report for Ausgrid, page 9.

[40] See Attachment B2, Greg Houston 2014, *Evaluation of Economic Regulation Authority's Draft Decision against the National Gas Objective*, ATCO Gas Australia's Response to the ERA's Draft Decision on required amendments to the Access Arrangements for the Mid-West and South-West Gas Distribution Systems.

[41] See Attachment B3, Geoff Swier 2014, *Economic considerations for the interpretation of the National Gas Objective*, Expert Report prepared for Jemena Gas Networks (NSW).

[42] See Attachment B4, Economic Insights 2011, *Regulation of Suppliers of Gas Pipeline Services – Gas Sector Productivity*, February, p. 33

industries which are most likely to have similar characteristics to the gas distribution industry are other infrastructure network industries. And of these industries, electricity distribution is likely to be the most similar.

2.2.4 AER obligation to make the NEO preferable decision

The NEL provisions

In addition to complying with the Rules, in making a distribution determination the AER must comply with a number of obligations imposed by the NEL that have the object of ensuring NEO preferable decision-making by the AER.

In making a distribution determination, section 16 of the NEL provides that the AER must:

- AER must perform or exercise a function or power under the NEL or the Rules that relates to the making of a distribution determination in a manner that will or is likely to contribute to the achievement of the NEO;[43]
- take into account the RPPs when exercising a discretion in making those parts of a distribution determination relating to direct control network services;[44]
- specify the manner in which the constituent components of the decision relate to each other and the manner in which that interrelationship has been taken into account in the making of the decision;[45] and
- if there are two or more decisions that will or are likely to contribute to the achievement of the NEO, make the decision that it is satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree (NEO preferable decision) and specify the reasons as to the basis on which the AER is satisfied that the decision is the NEO preferable decision.[46]

In summary, the AER is required to:

- perform or exercise a function or power under the NEL or the Rules that relates to the making of a distribution determination in a manner that will or is likely to contribute to the achievement of the NEO;

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[43] Section 16(1)(a) of the NEL and section 2(1) NEL definition of 'AER economic regulatory function or power'

[44] Section 16(2)(a) of the NEL

[45] Section 16(1)(c) of the NEL, and sections 2(1) and 71A NEL definitions of 'reviewable regulatory decision'

[46] Section 16(1)(d) of the NEL, and sections 2(1) and 71A NEL definitions of 'reviewable regulatory decision'

- determine the manner in which constituent components of the decision relate to each other and take those interrelationships into account in the making of the decision; and
- most importantly, where there are two or more decisions that will or are likely to contribute to the achievement of the NEO, make that which it is satisfied contributes to the greatest degree to the achievement of the NEO.

Consideration of overall decision and relevance of interrelationships

It is the overall decision that must be NEO preferable and the consideration of the interrelationships between constituent components of the decision and how they have been taken into account will, therefore, be of relevance to the assessment of whether a decision is the NEO preferable decision.

In introducing to section 16 of the NEL the requirements concerning interrelationships between constituent components and the making of the NEO preferable decision, the SCER (now COAG Energy Council) described these requirements as follows:[47]

> *...the regulator, in regulatory determination processes, … must … include in its final determination an explanation of the interlinkages between different component parts of its decision and how its overall decision is in the long term interests of consumers, in accordance with the NEO…*
>
> *In addition, the regulator, in regulatory determination processes, … must … where there is discretion around a range of decisions, make the overall decision that, on balance, it considers is materially preferable in terms of serving the long term interests of consumers as set out in the NEO…*

Because it is the overall decision that must be NEO preferable, the existence of error in a decision does not, of itself, establish that the decision is not NEO preferable or that another decision is materially preferable in making a contribution to the NEO. It is conceivable that the effect on the overall decision of two or more errors may offset one another, particularly given the interrelationships between constituent components of a distribution determination. At the same time, because of the interrelationships that exist between constituent components of a distribution determination, an error in the making of a decision may render the overall decision not NEO preferable notwithstanding that its effect on the constituent component of the decision in respect of which it is made is limited.

[47] SCER 2013, *Regulation Impact Statement Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks Decision Paper*, 6 June 2013, first page of executive summary of 'SCER's policy position'

These matters were discussed in an economic expert report recently prepared for, and submitted to the WA Economic Regulation Authority by, ATCO Gas Australia in the context of the analogous provisions of the NGL as follows:[48]

> *First, the process of assessing and reviewing elements of a regulatory decision necessarily involves making a series of determinations in relation to estimates or forecast future values of critical parameters. As a matter of principle, the judgments that must be applied may fall into error on either the upside or downside, with the effect that each may mitigate the other in terms of the end result. A requirement to consider the decision 'as a whole' against the materially preferable threshold, amounts to a practicable means for dealing in aggregate with a series of errors that, taken together, may not have much consequence.*
>
> *Second, many of the constituent decisions have economic linkages between one another, so that error in one has implications for another, even if, in its own terms, the second decision is appropriate. Further the emphasis on dynamic efficiency within the NGO - through its explicit emphasis given to the long term (as distinct from short term) interests of consumers, provides for the possibility that the correction of some errors warrants greater weight than the correction of others. By way of example, a depreciation decision that transferred the recovery of capital away from long term consumers and towards short term consumers should, on its face, receive a greater weighing in assessing what is preferable overall, than a depreciation decision that gave rise to the reverse effect.*

Decision-making that contributes to the achievement of the NEO

For the reasons discussed in section 2.2.1 above, the NEO is concerned with the interests of consumers in sustainably low prices, rather than the pursuit of short-term price reductions at the expense of their interests in the quality, safety, reliability and security of supply and the reliability, safety and security of the distribution system in the longer term - or, put another way, the striking of a balance between productive, allocative and dynamic efficiency that does not favour short-term gains in productive efficiency at the expense of dynamic efficiency. It follows that a decision that results in sustainably low prices while maintaining quality, safety, reliability and security will contribute to the achievement of the NEO and is (all else being equal) NEO preferable to a decision that pursues short-term price reductions at the expense of consumers' interests in quality, safety, reliability and security in the longer term or, put another way, short-term gains in productive efficiency at the expense of dynamic efficiency.

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[48] See Attachment B2, Greg Houston 2014, *Evaluation of Economic Regulation Authority's Draft Decision against the National Gas Objective*, ATCO Gas Australia's Response to the WA Economic Regulation Authority's Draft Decision on required amendments to the Access Arrangements for the Mid-West and South-West Gas Distribution Systems, p. 34

As the RPPs are the normative expression of the NEO, it can be assumed that a decision that is consistent with the RPPs will contribute to the achievement of the NEO, and that such a decision will (all else being equal) contribute to the achievement of the NEO to a greater degree than a decision that is not consistent with one or more of the RPPs.

Similarly, as the Rules are properly assumed to contribute to the achievement of the NEO and to be consistent with the RPPs, it follows that a decision that is consistent with those Rules, the scheme of those Rules and their object will contribute to the achievement of the NEO, and that such a decision will (all else being equal) contribute to the achievement of the NEO to a greater degree than a decision that is not consistent with the Rules, the scheme thereof or their object. It follows that any error or deficiency in the AER's constituent decisions in a distribution determination on the building blocks specified in clause 6.4.3 of the Rules that comprise a DNSP's revenue allowances will (all else being equal) compromise the achievement of the NEO and result in a decision that cannot properly be said to be a NEO preferable decision.

Unlawful decisions do not promote NEO and are not NEO preferable

A reviewable regulatory decision (including a distribution determination) made by the AER that is not in accordance with law cannot be said to contribute to the achievement of the NEO or, thus, constitute a NEO preferable decision for the purposes of section 16(1)(d) of the NEL. Rather, a decision is properly said to be a NEO preferable decision where, of the range of decisions that are in accordance with law, it is to be preferred on the basis that is makes the greatest contribution to the achievement of the NEO. This is evident from reading section 16(1)(d) of the NEL in its surrounding context and a consideration of the statutory intent of section 16(1)(d) disclosed by relevant extrinsic material.[49]

[49] Section 3 of the NEL provides that Schedule 2 to the NEL applies to the interpretation of the NEL. Clause 7 of Schedule 2 to the NEL provides that the interpretation of a provision of the NEL that will best achieve the purpose or object of the NEL is to be preferred to any other interpretation. Clause 8(2) of Schedule 2 to the NEL provides that, in the interpretation of a NEL provision, consideration may be given to 'Law extrinsic material' to provide an interpretation of an ambiguous or obscure provision, provide an interpretation that avoids a manifestly absurd or unreasonable result if the ordinary meaning leads to such a result or confirm the interpretation conveyed by the ordinary meaning of the provision. Clause 8(1) "Law extrinsic material" to mean "relevant material not forming part of this Law" and sets out a non-exhaustive list of examples. After noting the non-exhaustive nature of the list of "Law extrinsic material" set out in the definition of that term in clause 8(1) of Schedule 2 to the NEL, the Tribunal has concluded that "[t]he extrinsic material to which regard may be had is any material that may assist in the construction process": *Application by Energex Limited (No 4)* [2011] ACompT 4 at [23].

Section 16(1)(d) of the NEL must be read and construed in the context of the related provisions of the NEL introduced at the same time.[50] These relevantly include section 71P(2a), (2b) and (2c) of the NEL which provides (amongst other things) that the Tribunal:

- may only vary or set aside and remit a reviewable regulatory decision if satisfied that to do so will or is likely to result in a materially preferable NEO decision (in respect of which (amongst other matters) the establishment of a ground of review under section 71C(1) of the NEL must not, in itself, be determinative);
- must consider the reviewable regulatory decision as a whole in assessing the extent of contribution to the achievement of the NEO;
- must have regard to how the constituent components of the decision interrelate with each other and with the matters raised as a ground for review; and
- must specify in any determination varying or setting aside and remitting the reviewable regulatory decision the manner in which it has taken into account the interrelationship.

This alignment in the obligations of the AER and the Tribunal in respect of the making of the preferable NEO decision reflects a deliberate policy intention that a reviewable regulatory decision (including a distribution determination) by the AER make explicit how the NEO was taken into account in making that decision and provide the Tribunal with a starting point for its consideration. Specifically, the SCER made the following statement of intent in respect of the relevant NEL amendments:[51]

> *…the regulator will be required to provide an explanation of its decision-making process in its final determination and how its overall decision will contribute to delivering the long term interests of consumers as set out in the NEO and NGO. It is intended that this would provide both an explanation of the regulator's decision-making considerations and the logic that underpins its assumptions and approach, including the objectives and key interlinkages between components of the regulatory decision.*
>
> *It is intended that the record and the final determination will provide a clear starting point for the Tribunal in considering the merits of the matter before it and will ensure that it is explicit how the long term interests of consumers with regard to price, quality, reliability, safety and security of supply were taken into account in the original regulatory process.*

[50] Statutes Amendment (National Electricity and Gas Laws - Limited Merits Review) Bill 2013 (SA).

[51] SCER 2013, *Regulation Impact Statement Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks Decision Paper*, 6 June 2013, p. 40

It is evident from a consideration of SCER's policy statements regarding the establishment of the materially preferable NEO decision requirement for the grant of relief by the Tribunal on review that a reviewable regulatory decision, including a distribution determination made by the AER, that is not in accordance with law cannot be said to contribute to the achievement of the NEO or, thus, constitute a NEO preferable decision for the purposes of section 16(1)(d) of the NEL.

In its Decision paper on the review of the merits review regime under the NEL, the SCER (now COAG Energy Council) concluded in respect of the object of the limited merits review regime under the NEL that:[52]

> *… for the purposes of limited merits review applying to covered electricity and gas decisions in Australia, SCER considers the objective is to ensure that a decision is correct, in the sense of being made in accordance with the relevant law, or preferable, in the sense that, if there is a range of decisions that are correct in law, the decision that is ultimately achieved is the best that could have been made on the basis of the relevant facts.*

SCER concluded that the then merits review regime under the NEL had failed to deliver this policy objective in that error correction was occurring without apparent reference to how addressing the error contributed to the NEO against the background of the complex issues arising in reviewable regulatory decisions and the interrelationships between constituent components of those decisions. Specifically, the SCER stated:[53]

> *… SCER considers that the majority of the reviews taken to the Tribunal to date relate to differences of opinion on components of a final decision. Consequently, the Tribunal's focus on 'error correction' in isolation was not appropriate for the highly complex interlinkages and contentious nature of the issues for which reviews were sought by monopoly electricity and gas network businesses.*
>
> *The complexity of the issues being investigated has also led to situations where error correction has occurred without apparent reference to how addressing the error contributes to the NEO or NGO. For example, when considering the parameters that contribute to the rate of return that network businesses are allowed, decisions made by the Tribunal have increased the rate of return to about 10 per cent (noting there are some differences between different businesses). This amount was higher than both the original decision and the allowed rate of return previous*

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

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

jurisdictional regulators had set in their regulatory decisions. SCER considers such large changes, without reference to the energy objectives, undermines confidence in the review framework.

While the rate of return for monopoly businesses rightly varies between business [sic] and countries, making comparisons inappropriate, even if these decisions did support the NEO or the NGO there has been inadequate public reporting of these aspects of the decision-making process. SCER notes the notices published by the Tribunal outlining its process and reasoning behind its decisions have not included reference to how the decisions are in the long term interests of consumers with respect to price, quality, safety, reliability, and security of supply of electricity or gas, respectively.

It is this lack of information about how the review process has considered the 'facts, law and policy aspects of the original decision' that restricts the limited merits review regime in the full delivery of the original and recently clarified policy intent and is likely to continue to do so in the future if it is not addressed.

In addition, SCER recognises the intention in establishing the review regime was for the review process to be used rarely and only to address issues with a material consequence in the context of delivering the NEO or NGO, and meeting the review and pricing principles. However, the error correction approach adopted by the Tribunal may be leading to more appeals than would otherwise be the case.

The SCER emphasised that the intent of section 71P(2a) of the NEL is not to preclude the Tribunal from varying or setting aside and remitting a reviewable regulatory decision where this is necessary to deliver a correct decision; that is, a decision made according to law. Thus, the SCER observed:[54]

For the purposes of limited merits review applying to the energy sector under the NEL and NGL, the SCER is committed to ensuring that the approach adopted is consistent with wider administrative law, where the objective is to ensure that administrative decisions are 'correct or preferable'. That is, such decisions are:

- *correct, in the sense that they are made according to law; or*
- *preferable, in the sense that, if there are a range of decisions that are correct in law, the decision settled upon is the best that could have been made on the basis of the relevant facts.*

[54] SCER 2013, *Regulation Impact Statement Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks Decision Paper*, 6 June 2013, pp. 9-10

> *It is not the intention of the SCER for limited merits review to result in decisions that are not consistent with law. However, SCER recognises that a focus on error correction may lead to less optimal outcomes, particularly in complex determination processes where there may be disputes about many interlinked matters. In this context, 'error correction' means decisions that have been made without due regard to the facts, law and policy aspects of the original decision or decisions that should otherwise be 'preferable' decisions, as defined above. As set out in the consultation RIS, most decisions appealed under the limited merits review framework have been on subjective matters, where there are a range of decisions that are correct in law. Consequently, an undue focus on 'error correction', as defined above, reflects a failure of the limited merits review regime to deliver the policy intention.*

It follows that a decision that is "correct", in the sense that it is made according to law, is properly construed as being a "preferable NEO decision" or "materially preferable NEO decision" to a reviewable regulatory decision that is not in accordance with law.

The expression "according to law" may be construed as being a decision that the decision maker is empowered to make by the NEL and the Rules, and which is otherwise consistent with the requirements of the NEL and the Rules and of administrative law. However, the SCER recognised that there may be decisions that meet those criteria, that the Tribunal might nevertheless consider are attended by error in the manner in which the decisions are made, in that one or more of the grounds of review in section 71C(1) of the NEL exist.

It is important to bear in mind, in that context, that the grounds for review in section 71C(1) of the NEL are potentially very broad in their application, extend even beyond traditional administrative law review grounds, are capable of applying to constituent decisions, and may involve subjective considerations (particularly as to the exercise of discretions) about which minds may reasonably differ. Accordingly, it is possible that the reviewable regulatory decision under consideration has been made in accordance with law in the sense described above, despite the existence of a ground of review. It is for that reason that section 71P(2a)(d) of the NEL provides that the mere fact of the establishment of a ground for review under section 71C(1) of the NEL must not determine whether a materially preferable NEO decision exists.

That situation may be contrasted with a decision that is not made in accordance with law, in the sense that it is not consistent with the NEL and the Rules or the requirements of administrative law (for example, a decision that results from a misconstruction of a provision of the NEL and the Rules, with the consequence that the decision maker was not authorised by those provisions to make the decision made). It could not be said that, where an error exists of that nature, the decision might nevertheless be a "preferable NEO decision" or a "materially preferable NEO decision" which could not be varied or set aside to ensure that the decision made is in accordance with the requirements of the NEL and the Rules and administrative law.

Such a construction is consistent with the SCER's summary of its policy position concerning the intended effect of new sections 16(1)(d) and 71P(2a) of the NEL as follows:[55]

> *[T]he regulator, in regulatory determination processes, and the Tribunal, in review processes, must …* where there is discretion around a range of decisions*, make the overall decision that, on balance, it considers is materially preferable in terms of serving the long term interests of consumers as set out in the NEO or NGO…*

"Range of decisions", in this context, means decisions that are in accordance with law. It does not include decisions which are not in accordance with the NEL and the Rules and the requirements of administrative law. Put another way, a reviewable regulatory decision that is not made in accordance with law could not be regarded as a "NEO decision", that is, a decision which contributes to the achievement of the NEO.

Such a construction is also consistent with a presumption that the provisions of the NEL and the Rules promote their statutory object, being the NEO. Insofar as concerns the Rules, this is, in turn, consistent with the AEMC's express statutory obligation to make a Rule only if it is satisfied that the Rule will or is likely to contribute to the achievement of the NEO[56] and its statutory discretion to make a Rule that differs from a market initiated proposed Rule if the AEMC is satisfied that the more preferable Rule will or is likely to better contribute to the achievement of the NEO.[57]

Where there is discretion around a range of decisions, that is, there is more than one reviewable regulatory decision that is in accordance with law, section 16(1)(d) of the NEL requires the AER to make the decision that will or is likely to contribute to the achievement of the NEO to the greatest degree (and section 71P(2a) of the NEL requires the Tribunal to vary or set aside and remit the reviewable regulatory decision only if satisfied that to do so will or is likely to result in a decision that is materially preferable in making a contribution to the achievement of the NEO).

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[55] SCER 2013, *Regulation Impact Statement Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks Decision Paper*, 6 June 2013, statement of "SCER's policy position" in the preamble to that document

[56] Section 88 of the NEL

[57] Section 91A of the NEL

2.3 *Elements of the draft decision not in accordance with law*

As discussed in Section 2.2.4 above, ActewAGL Distribution contends that unless all the various elements of the draft decision are each in accordance with law, the draft decision is incapable of constituting a NEO preferable decision. As each of the elements of ActewAGL Distribution's revised regulatory proposal are in accordance with law and reflect the RPPs, prima facie a decision on the basis of its proposal is to be preferred in contributing to the achievement of the NEO.

Some of the key contentions that ActewAGL Distribution advances in support of its position that elements of the draft decision are not in accordance with law are discussed below. However, these are just examples of the numerous errors of law made in the draft decision.[58]

2.3.1 Opex (Chapter 3 of the revised regulatory proposal)

In its draft decision, the AER concluded that it was not satisfied ActewAGL Distribution's opex forecast reasonably reflected the opex criteria. Accordingly, the AER rejected the opex forecast included in ActewAGL Distribution's building block proposal. The AER determines a substitute base opex for 2012/13 of $42.2 million ($2013/14), as compared to ActewAGL Distribution's actual opex in 2012/13 of $66.8 million ($2013/14), that is a reduction to ActewAGL Distribution's base opex of 36.8 per cent.[59]

The AER used economic benchmarking to derive the substitute base opex which it then relied on to conclude that ActewAGL Distribution's actual expenditure in the 2012/13 base year was inefficient and to determine an alternative opex forecast.

The AER's draft decision on base year opex is not in accordance with law for the reasons discussed in Chapter 3 of the revised regulatory proposal, in particular in section 3.4.4.2. In summary, this is because:

- the provisions of Part E of Chapter 6, which specify the procedure for the making of distribution determinations, establish the submission of the regulatory proposal as the starting point for that procedure.[60] Similarly, clauses 6.5.6(c) and (d) and 6.12.1(d)(4) of the

[58] See also as further examples: cost pass through (as the AER's materiality requirement is inconsistent with the pass through regime established by the Rules (see section 11.5.2 of the revised regulatory proposal); and the AER's application of the STPIS (see section 12.4.5.1 of the revised regulatory proposal)

[59] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 7*, p. 7-19, Table 7.4, and p. 7-26, Table A.1

[60] See clause 6.8 of the Rules

Rules require the AER to assess a DNSP's proposed total forecast opex and provide for it to make adjustments to that forecast only where it is not satisfied that that forecast reasonably reflects the opex criteria;[61]

- the Rules further disclose that benchmarking is to be used as one only of a number of tools to assess ActewAGL Distribution's base year opex proposal and do not contemplate that such analysis will be given primacy.[62]

The AEMC has itself observed that benchmarking is no substitute for the role of a NSP's proposal,[63] however, the AER has, with only limited exceptions, put aside ActewAGL Distribution's proposed base year opex and instead given primacy to benchmarking analysis in making its decision on base year opex, relying on that analysis almost exclusively.

Before proceeding to rely on the results of benchmarking analysis, the AER should have undertaken a detailed analysis of the actual expenditure incurred by ActewAGL Distribution in the base year that comprised its proposed base year opex. This is particularly so given the size of the AER's proposed reduction to base year opex justified by reference to that benchmarking analysis.

2.3.2 Return on Debt (Chapter 8 of the revised regulatory proposal)

ActewAGL Distribution proposed its return on debt be calculated in accordance with the approach proposed by the AER in its Rate of Return Guideline, with three exceptions that ActewAGL Distribution proposed (see section 8.4.3 of the revised regulatory proposal). The AER rejection of that proposal is not in accordance with law as summarised below.

In making the draft decision, the AER misconstrues the term 'efficient financing costs', and therefore applies transitional arrangements that result in a return on debt that is not commensurate with the efficient debt financing costs of the benchmark efficient entity, contrary to the requirements of clause 6.5.2(b) and (h) of the Rules (see section 8.4.5.1 of the revised regulatory proposal). Instead, the AER's 10 year trailing average portfolio approach should be adopted immediately.

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[61] As discussed below in section 3.2.4, the AEMC affirms the scheme of the Rules disclosed by these provisions, observing that the regulatory proposal is 'the procedural starting point' for the determination of the opex allowance as '[t]he NSP has the most experience in how a network should be run'. See AEMC, 2012 Rule Determination, p. 111

[62] Clause 6.5.6(e) of the Rules

[63] AEMC, 2012 Rule Determination, p. 107

Further, in assessing the proposal that the averaging period for use in calculating the prevailing rate of return on debt in each of the regulatory years 2016/17, 2017/18 and 2018/19 of the regulatory control period be nominated by ActewAGL Distribution prior to the occurrence of that financial year, the AER has not provided reasons why its approach, as opposed to ActewAGL Distribution's proposed approach, contributes to the achievement of the NEO to the greatest degree.[64]

It is not clear to ActewAGL Distribution why the nomination of averaging period before the regulatory control period commences simplifies the annual updating process.[65] However, this is not a relevant consideration as the Rules do not operate to require a DNSP to nominate an averaging period during the regulatory control period (see clauses 6.3.1(c)(3), 6.5.2(l) and S6.1.3(9) and (9A)). In applying its self-determined conditions the AER has failed to comply with the Rules (see section 8.4.5.2 of the revised regulatory proposal).

2.3.3 'True-up' for the transitional regulatory period (Chapter 9 of the revised regulatory proposal)

The AER provides for an adjustment or 'true-up' in respect of the difference between the annual revenue requirements (ARRs) for the transitional regulatory period for distribution and transmission approved by the AER in its placeholder determination and the notional ARRs for the transitional regulatory period determined in its draft decision. In performing this 'true-up', however, the AER makes a modification to the amount of the ARR that it approved in the placeholder determination for the transitional regulatory period for ActewAGL Distribution's distribution network to account for a change in the energy throughput forecast for 2014/15 accepted by the AER as between the placeholder determination and the draft decision. That 'true-up' modification is not in accordance with law.[66] The transitional regulatory period 'true-up' amount for the purposes of clause 11.56.4(h) and (i) of the Rules is in fact $27.6 million ($nominal) and not $33.7 million as calculated by the AER (see section 9.5 of the revised regulatory proposal).

[64] As required by section 16(1)(d) of the Law

[65] It appears the same amount of work is required by both ActewAGL Distribution and the AER, the difference is when that work occurs. In any event, as there is an annual updating process it is not possible for the AER to undertake all of the necessary work as part of its final determination.

[66] In Attachment F12 to the revised regulatory proposal, ActewAGL Distribution provides its detailed legal reasoning and analysis in support of these contentions

2.3.4 Metering Services (Chapter 14 of the revised regulatory proposal)

The AER's draft decision to classify the recovery of residual type 5 or type 6 meter capital costs as a discrete, additional standard control service, and so provide for the transfer of a portion of ActewAGL Distribution's metering RAB to the standard control services RAB during the subsequent regulatory period and the smeared recovery of that RAB value through general network tariffs from the general customer base, is not in accordance with law (see section 14.3.3.2 of the revised regulatory proposal) for reasons which include:

- the discretion conferred on the AER by the Rules in respect of the constituent decision on classification is one to classify a distribution service or direct control service to be provided by ActewAGL Distribution.[67] The AER is not empowered to classify the recovery of a category or type of costs divorced from any service to be provided by ActewAGL Distribution;
- the Rules prohibit the inclusion in the RAB for standard control services, and the recovery through charges for those services, of the value of assets that are not used by ActewAGL Distribution in the provision of standard control services;[68] and
- the Rules do not permit the addition to the RAB for standard control services during a regulatory control period of the value of assets not previously included therein, however, the AER expressly states that it seeks to effect just such a result through its classification of the recovery of residual type 5 or type 6 meter capital costs as a standard control service and its proposed B factor adjustment.[69]

2.4 Central focus on benchmarking in the AER's opex draft decision does not promote the NEO

In this section, ActewAGL Distribution submits that the AER's primary focus on productive efficiency through the application of its benchmarking allowance is not in the long term interests of consumers. Furthermore, the sole reliance on benchmarking when it must have regard to other opex factors would not be consistent with the NEO. Finally, there are significant broader implications of the mechanistic use of benchmarking: it can lead to error in setting the opex allowance and also increases the potential for opex allowances that are not achievable; both

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[67] Clauses 6.2.1(a) and 6.2.2(a) of the Rules

[68] Clause 6.5.1(a) and S6.2.1(e)(8) of the Rules

[69] Clauses S6.2.1(e), including in particular paragraphs (6) to (8), and S6.2.3(e)

instances are not in the long term interests of consumers including in particular for the reasons discussed in Section 2.6 below.

2.4.1 Sole focus on productive efficiency is not in the long term interests of consumers

The AER states in its overview that it considers that the NEO covers all three aspects of efficiency. Nonetheless, the AER has focused on short term productive efficiency at the expense of long term dynamic efficiency:

> *We consider productive efficiency is the most relevant for assessing cost forecasts*[70]

By choosing to accord greater weight to one dimension of efficiency over others, the AER has erred in not having had equal regard to all of the relevant aspects of efficiency. In particular, its fails to properly take into account allocative efficiency by proposing expenditure cuts that are insufficient to serve consumers with a safe, secure and reliable electricity supply. Additionally, the interests of consumers with which the NEO is concerned are their "long term" interests, which necessitates a consideration of dynamic efficiency.

2.4.2 Benchmarking is only one several factors to be considered by the AER

The primacy that the AER has placed on its use of benchmarking to promote productive efficiency is not in the long term interests of consumers and contrary to the NEO. The AER draft decision states:

> *Benchmarking is central to our task of assessing expenditure forecasts.*[71]

However, benchmarking is only one of the nine expenditure factors that the AER has to have regard to under the Rules.

The AER has chosen to add two other expenditure factors, both of which relate to benchmarking.

- The AER's benchmarking data sets including, but not necessarily limited to:

  (a) data contained in any economic benchmarking RIN, category analysis RIN, reset RIN or annual reporting RIN

  (b) any relevant data from international sources

  (c) data sets that support econometric modelling and other assessment techniques consistent with the approach set out in our Guideline

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[70] AER Draft Decision for ActewAGL Distribution, page 7-38

[71] AER, 2014, *Draft decision ActewAGL distribution Determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-60

as updated from time to time.

- economic benchmarking techniques for assessing benchmark efficient expenditure including stochastic frontier analysis and regressions utilising functional forms such as Cobb Douglas and Translog.

The AER's inclusion of these two additional factors is further evidence of the primacy it has accorded to its benchmarking analysis in assessing and forming its conclusion on the efficient level of operating expenditure.

The AER effectively interprets any differences in benchmark outcomes as representing differences in efficiency. Where benchmarking is not giving robust results, and where there is no intuitive corroboration that differences are due to inefficiency (rather than unexplained factors), then ActewAGL Distribution submits that basing the determination on benchmark outcomes may violate the revenue and pricing principles as well as the expenditure criteria in the Rules, and would not be consistent with the NEO.

In a leading academic paper prepared a NERA economist Graham Shuttleworth, he notes:[72]:

> *..strictly speaking, the residual …represents the costs that the model has ''failed to explain''. Interpreting it as ''inefficiency'' is unjustified, since it may be due to any combination of omitted or even unique factors. …The residual gap between the frontier and any observation could, in principle, be due to any factor not contained in the model. …The costs of each network depend on a large number of factors, some highly specific to its location, or possibly even unique.*

In contrast to claims by the AER, its benchmarking analysis does not enable it to 'objectively examine efficiency'.[73] ActewAGL Distribution contends that it is extremely difficult to objectively determine efficiency.

This difficulty is compounded by the fact that, as a consequence of changes in input costs, production techniques and consumer preferences, what constitutes an efficient outcome is constantly changing and cannot be directly observed. NERA (2014) opined on this[74]:

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[72] See Attachment C30, Shuttleworth, G. 2005, *Benchmarking of electricity networks: Practical problems with its use for regulation*, Utilities Policy, vol. 13, p.310-317.

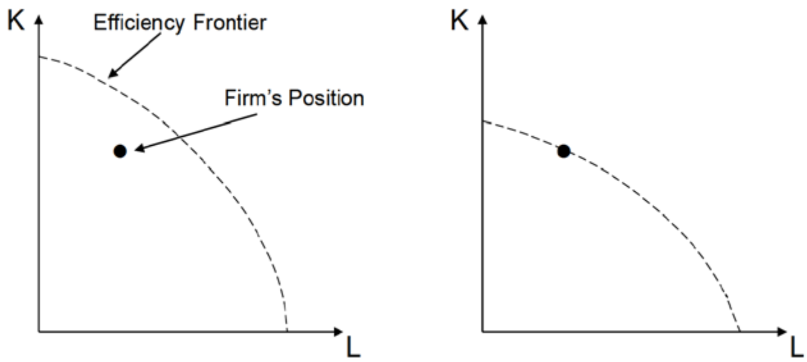
[73] AER, 2014, *Draft decision ActewAGL distribution Determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-60

[74] See Attachment B1, NERA, 2014, *Economic Interpretation of Clauses 6.5.6 and 6.5.7 of the National Electricity Rules,* Report for Ausgrid., pages 6-7

A key consequence of the above definition of efficiency is that what constitutes an efficient outcome will be constantly changing. …

….

Figure [..] below illustrates the difficulty of determining whether or not a firm is efficient, if the efficiency frontier cannot be directly observed. If the efficiency frontier is assumed to be as depicted in the diagram on the left hand side, then a firm operating at the point indicated would be considered not to be perfectly efficient. However, if the frontier it is assumed to be as depicted in the right hand side diagram, then the same firm would be considered to be perfectly efficient. If there is no external measure of where the efficiency frontier lies, then there in no way of knowing which of these cases applies.



A consequence of efficiency not being directly observable, and of always changing, is that the provision of appropriate incentives within the regulatory regime will be a key component in leading to outcomes that achieve dynamic efficiency, and are in the long-term interests of consumers.

In addition, it is not realistic to expect each firm to be always operating on the efficiency frontier.[75]

The economics textbook definition of efficiency is underpinned by the concept of perfect competition. A perfectly competitive market ensures that firms are always producing at least cost, and are constantly evolving to ensure that they continue to produce the optimal mix of goods and services at least cost over time.

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[75] Attachment B9, NERA, 2014, *Economic Interpretation of Clauses 6.5.6 and 6.5.7 of the NER*, Ausgrid, May, pages 6 to 7 (of the unmarked version)

> *In the real world there are constraints on firms constantly altering their mix of goods and services and production processes, to take account of new technology and changes in consumer tastes. Companies' abilities to transform inputs into outputs efficiently will vary over time and will be constrained by their specific operating environments. This is particularly true for firms operating in industries that are capital intensive and where there are long-lived assets, such as infrastructure businesses.*
>
> *It is therefore unrealistic to expect a firm to always be operating on the efficiency frontier. Even if a firm is on the efficiency frontier at one point in time, it is unlikely also to be on it a moment later, as the frontier itself will have moved. In practical terms, efficiency is something that firms may be constantly working towards, without ever actually achieving.*
>
> *… Importantly, the attainment of perfect frontier efficiency is not directly observable. Under the construct of a perfectly competitive market, whether or not a firm is operating on the efficiency frontier can be deduced from observing whether or not it remains in business. Firms that are not perfectly efficient will be undercut by firms that are, so that inefficient firms will no longer be able to sell their output. However, in the real world firms operate in markets that are less than perfectly competitive and so this external gauge of whether or not a firm is achieving frontier efficiency is no longer available.*

2.4.3 Broader implications of benchmarking

ActewAGL Distribution's rejects the use the AER's benchmarking analysis, for the reasons articulated in detail in Chapter 3.

Furthermore, ActewAGL Distribution does not believe that the AER's purported supporting analyses – partial productivity indicators, category analysis, detailed review of labour and vegetation management costs – are sufficiently robust to draw any confirmation or satisfactory conclusions about ActewAGL Distribution's efficiency. Rather the claimed supporting analyses are highly selective, demonstrate little understanding of differences across DNSPs, and therefore suffer from data reliability, and lack of normalisation of operating and environmental factors.

The reckless opex cuts proposed by the AER solely based on benchmarking results have broader implications for the incentives faced by ActewAGL Distribution and therefore the achievement of dynamic efficiency. In an expert report for ActewAGL Distribution, Mr. Greg Houston describes how the AER's proposed approach can lead to ActewAGL Distribution facing considerable costs in the event that the company fails to achieve the benchmark level of opex. In explaining the broader implications, Mr Houston notes that the AER's approach is premised on the notion that that expenditure above the 'efficient level' – as established through the benchmark – is always undesirable. He presents two cases where this fails to be the case:

> ***The benchmark is in error***

A critical requirement for the responsible use of a benchmark expenditure allowance is for the benchmark to be a reasonable reflection of the 'efficient level' of expenditure for a DNSP. Significant risks arise in circumstances where the opex allowance underestimates the efficient level of expenditure, ie, the benchmark is too low.

Adoption of a benchmark that is too low not only fails to provide the right incentive to a DNSP, but may encourage a DNSP to make decisions that are contrary to the long term interests of consumers. Most notably, a benchmark opex allowance that is 'too low' encourages a DNSP to spend less on opex than is efficient – because it bears more than 100 per cent of any expenditure above the opex allowance.

These interactions inevitably cause significant attention to be given to the degree to which the benchmark can be relied upon, and the risk of disconnect between the benchmark and actual efficient levels of expenditure. The merits of the AER's benchmarking approach are beyond the scope of my report. Nevertheless, I note that the greater the uncertainty associated with the benchmark level of opex, the greater the potential for benchmarking of businesses to have detrimental outcomes for consumers.

The benchmark is not achievable

Even if the benchmark were assumed to be free of uncertainty, it does not follow that the benchmark is achievable. I have already described circumstances where a business might not respond to the incentives provided by the regulatory framework, a corollary of which is a DNSP not being able to achieve its benchmark level of opex.

In the event that a business cannot achieve the benchmark, the end result is ultimately a loss of revenue for the DNSP – revenue that the DNSP requires to maintain its network and ensure reliable supply to its customers. This gives rise to the question of whether adherence to an efficient but unachievable benchmark leads to recovery of the level of revenue that is consistent with the long term interest of consumers. In my opinion, it does not. [76]

2.5 Retrospective changes to the regulatory framework do not promote the NEO

The AER's draft decision gives effect to a number of changes in its regulatory approach effected by the draft decision that result in material financial losses for ActewAGL Distribution:

- The application of the change to the AER's regulatory approach to forecasting opex in the (largely ex-post) setting of the notional revenue requirement for 2014/15.

[76] See Attachment C1, HoustonKemp, 2015, *Opex and the efficiency benefit sharing scheme*, January, pages 25-26

- Failure to give effect to the regulatory arrangements contemplated by the application of the EBSS in the previous regulatory control period.

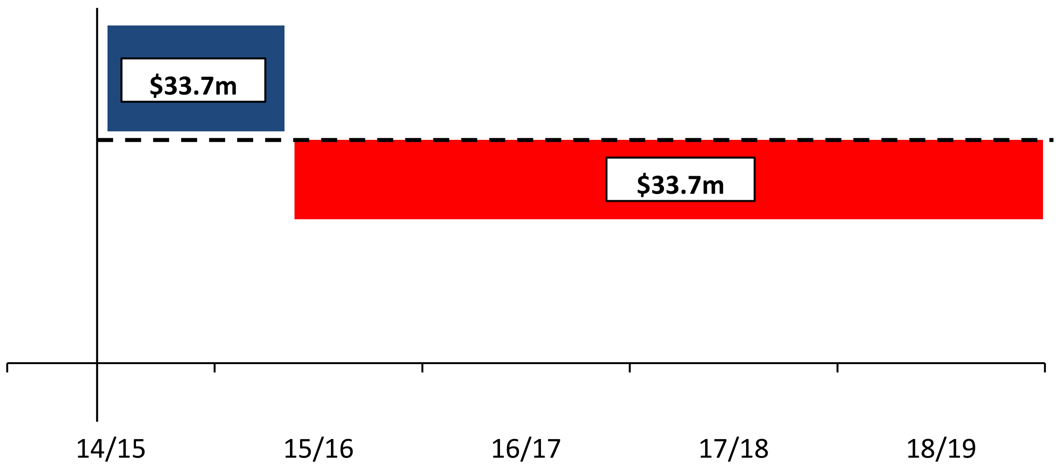
ActewAGL Distribution contends that these material financial losses arising from the retrospective application of changes in the AER's regulatory approach will result in ActewAGL Distribution's effective expenditure allowances for the subsequent regulatory period being significantly lower than even the AER's estimate of efficient expenditure for that period. This cannot be reconciled with the scheme of the regime, effected in the section 7A(2) RRP, that ActewAGL Distribution be accorded a reasonable opportunity to recover its efficient costs of achieving the opex and capex objectives and that prices support the maintenance of quality, safety, reliability and security. It follows that a final decision, based on the draft decision, is detrimental to the achievement of the NEO and cannot be said to be NEO preferable.

2.5.1 Retrospective change in opex allowance

In accordance with the requirements of the Rules, the AER's draft decision provides for an adjustment or 'true-up' in respect of the difference between the ARR for the transitional regulatory period for distribution and transmission approved by the AER in its placeholder determination and the notional ARR for the transitional regulatory period determined in its draft decision. This is covered in more detail in Chapter 9 of this revised regulatory proposal.

As ActewAGL Distribution's notional ARR for the transitional regulatory period is set (largely ex-post) on the basis of the AER's changed regulatory approach to determining expenditure allowances, in particular by reference to its economic benchmarking analysis, it follows that ActewAGL Distribution's total revenue requirement for the subsequent regulatory period will be materially lower than that which would be consistent with the AER's estimate of efficient and prudent opex in the SRP. This is illustrated in Figure 2.1 below.

Figure 2.1 Retrospectivity and 2014/15 "true-up"[77]



Even if it was practicable having regard to safety, quality, security, and reliability considerations for ActewAGL Distribution to reduce its opex to the extent contemplated by the opex allowances proposed in the AER's draft decision, this may take several years. A further discussion of this point follows in Section 2.7.3.

Of particular relevance here is that close to seven months of the transitional regulatory period have already elapsed and the majority of the transitional regulatory period will have elapsed by the time the AER makes its distribution determination for the subsequent regulatory period in late April 2015.

ActewAGL Distribution will therefore not have been afforded the opportunity to make changes in the transitional regulatory period. The practical effect of the AER's draft decision is that the opex cuts would actually be greater than indicated in the draft decision because the decision is to be backdated to July 2014.

Table 2.3 shows the impact of the AER's draft decision to retrospectively apply the opex allowance to the transitional regulatory period two scenarios:

- Scenario 1 - ActewAGL Distribution incurs the opex specified in the transitional determination of $73.5 million for the transitional regulatory period compared to an

[77] This illustration only covers the true-up for distribution services. Retrospective adjustment has also been applied to transmission services, which ActewAGL Distribution rejects.

opex allowance determined by the AER in the draft decision of $42.6 million – a difference of $30.9 million. Given that the AER's adjustment is retrospective, ActewAGL Distribution will need to spend less than the AER's estimate of the efficient level of opex in the subsequent regulatory period to keep within the overall $220.3 million opex allowance for the 2014-19 period. This results in an effective opex reduction of over 50 per cent for the subsequent regulatory period.

- Scenario 2 – Similar to Scenario 1 above, ActewAGL Distribution incurs the opex allowance specified in the transitional determination of $73.5 million yet due to the AER's retrospective adjustment recovers $34.2 million less. To bring down opex to the AER's estimate of efficient levels, ActewAGL Distribution must also incur significant restructuring costs of [c-i-c [redacted]][78] that are not currently part of the regulatory allowance set by the AER and results in the AER's allowance for 2014/15 being [c-i-c [redacted]] less than incurred. To operate within the overall $220.8 million opex allowance for the 2014-19 period, ActewAGL Distribution would be required to operate at opex levels significantly lower than the AER's estimate of the efficient level. This results in an effective opex reduction of over [c-i-c [redacted]] for the subsequent regulatory period.

[78] Further details of this are covered in Section 2.7.3

Table 2.4 Impact of the AER's retrospective adjustment ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
AER draft decision						
ActewAGL Distribution's proposal	76.8	75.0	73.1	75.7	77.2	377.9
AER's draft decision	42.6	43.3	44.2	44.9	45.7	220.8
Difference	-34.2	-31.7	-28.9	-30.7	-31.5	-157.1
Implied reduction	*44.6%*	*42.2%*	*39.5%*	*40.6%*	*40.8%*	*41.6%*
Scenario 1: There is no time to adjust expenditure in year 1*						
Forecast Actual ActewAGL Distribution to stay within overall allowance	73.5	33.9	34.6	35.3	35.9	213.3
Implied reduction	*4.4%*	*54.8%*	*52.06%*	*53.4%*	*53.5%*	
Scenario 2: Restructuring costs to transition business to AER's perceived efficiency level						
Restructuring costs	[cic [redacted]					
Forecast Actual ActewAGL Distribution to stay within overall allowance*	[ci [redacted]	[ci [redacted]	[ci [redacted]	[ci [redacted]	[ci [redacted]	[ci [redacted]]
Implied reduction		*[ci [redacted]*	*[ci [redacted]]*	*[ci [redacted]]*	*[ci [redacted]*	

**Note: Both scenarios assume that overspending during 2014/15 is recovered smoothly over the remaining four years of the regulatory period.*

Both scenarios described above assume that ActewAGL Distribution could immediately transition to an implied efficient level at the end of 2014/15. This is clearly unrealistic and therefore inconsistent with clause 6.5.6(c) of the Rules.

Furthermore, failure to provide an adequate expenditure allowance, by retrospectively lowering the opex allowance, and by not factoring in any restructuring costs is likely to lead to ActewAGL Distribution operating with expenditure allowances that are well below the implied efficient levels determined by the AER. This increases the risk that electricity cannot be provided in a safe, secure and reliable manner, and therefore such an approach by the AER does not contribute to the NEO.

As ActewAGL Distribution submits in section 2.7, opex reductions of this magnitude would be devastating, and would severely impact its ability to provide satisfactory levels of service in the future. The outcome would be a much higher rate of unplanned service interruptions due to asset failure, affecting most of its consumers.

2.5.2 Retrospective removal of the EBSS

The magnitude of opex cuts proposed by the AER in sole reliance on benchmarking results has broader implications. In an expert report for ActewAGL Distribution, Mr. Greg Houston notes that the AER's approach leads to unanticipated and material financial losses:

> *The proposed opex arrangements set out in the draft decision retrospectively change the sharing of cost overruns experienced in the 2009/10-2013/14 regulatory control period. The existing opex arrangements set out prior to the start of the 2009/10-2013/14 regulatory control period clearly intended that with the EBSS, the DNSP and consumers would share the benefits or fund the cost of differences between the level of opex forecast and that actually incurred by the DNSP.[79] Further, the benefits or costs of any differences would be shared between the DNSP and its customers on a 30:70, basis.*
>
> *However, the AER's draft decision of November 2014 now proposes that, for expenditure that occurred between 1 July 2009 and 30 June 2014, ActewAGL must bear 100 per cent of the opex costs in excess of the allowance determined by the AER. This retrospective change in the sharing ratio has material financial consequences given that ActewAGL overspent its EBSS target level of opex by $44.9 million (2013/14 dollars) during this period.* ***To maintain the intended sharing ratio of 30:70 would require the AER to add $36.7 million (2013/14 dollars) to ActewAGL's 2014-15 revenues.***
>
> *A failure to adjust revenue to achieve the sharing ratio operating under the 2008 EBSS increases the level of uncertainty in the regulatory environment and, in so doing, substantially increases the level of regulatory risk. Regulatory risk increases the prospect of investors' expectations as to the return on or of capital for a particular project not being met, and so increases a regulated firm's cost of providing capital, to the detriment of the long term interests of consumers.*
>
> ***In my opinion, retrospective changes to the regulatory framework that result in unanticipated and material financial losses to a DNSP are unnecessary and inconsistent with the long term interests of consumers as required by the NEO.[80] (emphasis added)***

[79] See AER, *Electricity Distribution Network Service Providers Efficiency Benefit Sharing Scheme | Final Decision*, June 2008, page 23.

[80] See Attachment C1, HoustonKemp, 2015, *Opex and the efficiency benefit sharing scheme*, January, page 26

2.6 Relationships between constituent decisions

In this section, ActewAGL Distribution contends that:

- the AER's opex draft decision undermines the incentive regime operated through the efficiency benefits sharing scheme (EBSS);
- the AER's opex and capex draft decision undermines the service target performance incentive scheme (STPIS);
- the AER has erred in not taking into account the inter-relationship between its constituent draft decisions on opex and capex in setting the expenditure allowances; and
- the AER errs by making drastic reductions to opex and capex allowances, and when combined with the retrospective removal of the EBBS, fails to adjust the equity beta for the increased risk faced by investors. This is discussed in Chapter 8 of the revised regulatory proposal.

Each of these interrelationships, and ActewAGL Distribution's contentions in support of the proposition that the manner in which the draft decision addresses each of them is detrimental to the achievement of the NEO, are discussed in turn below.

2.6.1 Implications of the opex draft decision on EBSS

The AER's draft decision has substantial implications in relation to the incentives provided to DNSPs. For reasons explained below, ActewAGL Distribution considers that the draft decision is inconsistent with section 7A (3) of the NEL:

> *A regulated 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 –*
>
> *(a) Efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and*
>
> *(b) The efficient provision of electricity network services; and*
>
> *(c) The efficient use of the distribution system or transmission system with which the operator provided direct control network services.*

Furthermore, pursuant to clause 6.5.8 of the Rules:

> *The AER must, ….,develop and publish an incentive scheme or schemes (efficiency benefit sharing scheme) that provide for a fair sharing* [emphasis added by ActewAGL Distribution) *between Distribution Network Service Providers and Distribution Network Users of:*

> (1) *The efficiency gains derived from the operating expenditure of Distribution Network Service Providers for a regulatory control period being less than; and*
>
> (2) *The efficiency losses derived from the operating expenditure of Distribution Network Service Providers for a regulatory control period being more than,*
>
> *The forecast operating expenditure accepted or substituted by the AER for that regulatory control period.*

In the draft decision, the AER outlines that for the 2014-19 period it will not rely on the revealed cost incurred by ActewAGL Distribution in the base year, 2012/13. Instead the AER has made a substitute opex decision for the base year using results of its benchmarking analysis. ActewAGL Distribution considers that it is inconsistent with fundamental principles of incentive based regulation and the incentive framework as set out in the EBSS because:

(1) ActewAGL Distribution has had a strong incentive during the 2009-14 period to reveal its efficient cost.

(2) It undermines the opportunity (and incentive) for businesses to implement efficiency savings that in the short term require higher opex. By reducing the base year opex the AER sends a signal to businesses that businesses cannot invest in higher expenditure in the short term to achieve future efficiencies, because they run the risk that the AER will refer to benchmarking and remove the benefit from future savings by allowing a lower operating expenditure than the revealed costs. In other words, the adoption of an allowance based on benchmarking fails to provide the right incentive to businesses to incur expenditure that will result in future cost savings, to the long term interest of consumers.

(3) Adoption of a benchmark opex that is too low encourages the businesses to make decisions that are contrary to the long term interests of consumers by spending less on opex than efficient.

(4) The proposed application of the EBSS by the AER is asymmetrical in relation to sharing of efficiency gains, losses and risks. Even if a DNSP is able to outperform the benchmark, if the allowance is based on a benchmark the sharing 30:70 between customers and businesses cannot be achieved.

In an expert report for ActewAGL Distribution, Mr. Greg Houston notes that departing from the revealed costs approach to setting opex allowance does not reward the DNSPs for efficiency gains and the proposed arrangements do not provide a continuous incentive:[81]

> *the application of these proposed changes profoundly alters the incentives of network businesses, relative to the original design objective.…*
>
> *the distortion to the incentive framework created in the draft decision cause ActewAGL to bear the full cost of the opex over runs incurred during the 2009-14 period. Through its retrospective change the sharing arrangements contemplated at the start of the 2009/10-2013/14 regulatory control period, the draft decision alters the share of opex overruns between ActewAGL and its customers from a 30:70 basis, to one where ActewAGL bears 100 per cent of its $44.9 million (2013/14 dollars) opex cost overrun.*
>
> *To maintain the intended sharing ratio of 30:70 would require the AER to add $36.7 million (2013/14 dollars) to ActewAGL's 2014-15 revenues…*
>
> *The proposed changes give rise to incentive arrangements that are wholly inconsistent with the principles set out in clause 6.5.8(c) of the rules. The deficiencies I have identified show that the incentive arrangements sitting within the combination of measures proposed by the AER are deeply flawed. In my opinion, the draft decision gives insufficient attention to the long term incentives its create, and undermines the existing regulatory framework that, with the introduction of the CESS, would otherwise have aligned the incentives on a DNSP to deliver long term efficiency.*

ActewAGL Distribution submits that the expert opinion demonstrates that the implications of the AER's opex draft decision and the AER's decision in relation to the EBSS are not in the long term interest of consumers.

2.6.2 Inter-dependency between opex and capex decisions on STPIS

The STPIS performance targets are related to ActewAGL Distribution's total forecast opex and capex because the STPIS targets must be modified for any planned reliability improvements and any other factors that are expected to materially affect network reliability performance.

In setting STPIS performance targets, the AER has not taken into account the requirement for opex and capex forecasts to comply with regulatory obligations, as distinct from maintaining reliability.

In an expert report for ActewAGL Distribution, Mr Greg Houston notes that the proposed opex reductions undermine the STPIS incentive framework:

[81] See Attachment C1, HoustonKemp, 2015, *Opex and the efficiency benefit sharing scheme*, January, page 17-25

ActewAGL is subject to the national distribution service target performance incentive scheme (STPIS). STPIS provides a financial incentive to ActewAGL to maintain and improve service performance and is calibrated so the distributor retains the value of any incremental improvements (or bears the cost of any incremental deteriorations) in service performance for a period of 5 years. Under the STIPS, the DNSP retains approximately 25 per cent of the value of any improvements in service performance as well as bearing 25 per cent of the value of any reductions in service performance.

It follows that the STIPS closely aligns to the incentives provided through both the current, 2008 EBSS and the CESS. However, this alignment is destroyed by the proposed opex arrangements set out in the draft decision. In particular, for so long as a DNSP's actual opex is above the efficient level suggested by the AER's benchmarking analysis, it has a strong incentive to reduce service performance so as to minimise the opex penalty. This distortion arises because, under the incentives implied by the draft decision, a DNSP would bear 100 per cent of the cost being above the level of the AER's opex allowance. In contrast, under the STIPS, the DNSP would only bear 25 per cent of the value of the change in service performance.

It follows that, under the proposed opex arrangements, a DNSP would:

not have an incentive to incur any additional opex costs in order to improve service performance, even if it was efficient to do so; and

have an incentive to reduce opex costs, even if it results in an inefficient deterioration in service performance.

It is difficult to reconcile how the distortion between the incentives for service performance and those that operate for opex, which could potentially result in inefficient levels of service performance, could be in the long-term interests of consumers, or consistent with the NEO.[82]

2.6.3 Interdependency between the opex and capex draft decisions

Background to the AER's draft decision

Under the Rules specifying the opex and capex factors, the AER is required to have regard to the substitution possibilities between opex and capex.

In its capex draft decision, the AER makes a passing mention to substitution possibilities between opex and capex.[83] In reaching its conclusions on setting a capex allowance, which has been

[82] See Attachment C1, HoustonKemp, 2015, *Opex and the efficiency benefit sharing scheme*, January, page 26 and 27

[83] AER Draft Decision, Attachment 6, Table 6.5, 6-29

reduced by a drastic 35 per cent for the 2014-19 period, the AER did not assess, for any capex category or project, whether the effect of the capex reduction would result in higher operating costs.

In particular, the AER did not consider the implications for ActewAGL Distribution's reactive maintenance of its substantial reduction to ActewAGL Distribution's replacement expenditure (repex) allowance. This was despite ActewAGL Distribution having highlighted in its regulatory proposal that a key driver of its proposed repex program is to reduce maintenance costs.

Similarly, in its opex draft decision, the AER makes a passing reference to substitution possibilities between opex and capex expenditure.[84] In reaching its conclusions the opex allowance, which has been reduced by an unprecedented 42.35 per cent for the 2014-19 period, the AER did not assess whether ActewAGL Distribution may require investment in upgraded systems and technology to close the perceived efficiency gap.

Rather, the AER makes harsh reductions to both the opex and capex allowances.

Risks of failing to consider the substitution possibilities between opex and capex

There are significant risks associated with regulators applying benchmarking or bottom-up assessments to different sub-sets of total costs. These risks are recognised in a report prepared by NERA economist Graham Shuttleworth:[85]

> *For each subset, companies may achieve the lowest costs only by spending money on other subsets, eg, they may lower opex by investing in new capital equipment and vice versa. The danger with such partial measures of "efficiency" is that the regulator combines the lowest (or "most efficient") costs for each subset from different companies, thereby producing an overall estimate of costs which is simply infeasible and an unreasonable basis for setting targets.*

Consideration of capex-opex trade-off by ActewAGL Distribution

The required trade-off analysis is usually undertaken with respect to refurbishment and replacement of ageing and potentially unreliable equipment, where the ongoing maintenance, repair, and fault costs (including loss of supply) can be compared with the capital cost of refurbishment and replacement. An example of a capex-opex trade-off evaluation undertaken in preparing the capex forecasts for the 2014-19 period is that relating to ActewAGL Distribution's decision to install fibreglass poles in backyards instead of wood poles to reduce life cycle costs of maintenance of those assets.

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[84] AER Draft Decision, Attachment 7, Table 7.7, 7-23.

[85] See Attachment C30, Shuttleworth, G. 2005, *Benchmarking of electricity networks: Practical problems with its use for regulation*, Utilities Policy, vol. 13, p.310-317

The consideration of capex-opex trade-offs within ActewAGL Distribution’s total capex forecast is a key component of ActewAGL Distribution’s top-down assessment process. This is discussed further in Chapter 4.

Conclusion

In the absence of any changes to opex allowances resulting from the capex constituent decision, and in the absence of any changes to the capex allowance despite reduced opex allowances arising from the opex constituent decision, ActewAGL Distribution considers the final decision will not contribute to the achievement of the NEO or be NEO preferable.

2.7 Implications of the draft decision for long term interests of consumers with respect to reliability, security and safety

2.7.1 Overview

The magnitude of the proposed reductions in expenditure allowances by the AER in its draft decision relative to those proposed by ActewAGL Distribution in its regulatory proposal for the subsequent regulatory period and those allowed for previous regulatory periods is unprecedented in regulation of electricity network businesses in Australia. The effect of these reductions is exacerbated by the fact that the draft decision is retrospective in nature, which means that one year of the five year period for which the AER is determining expenditure allowances will be almost completed at the time of the AER’s final decision. The retrospective nature of the draft decision is discussed in section 2.5 above.

In this section, ActewAGL Distribution:

- contrasts a comparison of historical regulatory allowances to the expenditure allowances proposed in the draft decision with the growth in ActewAGL Distribution's network and customer numbers to establish that, whereas the reductions proposed in the draft decision result in expenditure allowances not seen for over 15 years in the case of opex and 7 years in the case of capex, growth in ActewAGL Distribution's network and customer numbers suggest expenditure required to achieve the opex and capex objectives has increased over this time (in section 2.7.2 below);
- outlines the likely business model inherent in the AER's draft decision, i.e. required to meet the expenditure allowances proposed by the AER in that Decision, and time required to transition ActewAGL Distribution's business to that business model (in section 2.7.3 below); and
- particularises the likely consequent effects of the draft decision on reliability, security and safety (in section 2.7.4 below).

ActewAGL Distribution contends that it is evident from the likely effects of the draft decision on reliability, security and safety in particular that the proposed expenditure allowances in the draft decision, if reflected in the AER's final decision, will deliver a short-term reduction in price at the cost of a significant compromise to the long term interests of consumers with respect to reliability, security and safety. As discussed in sections 2.2.1 and 2.2.4, this would be contrary to the NEO, as it has been construed by the Tribunal and policy-makers and would, thus, be detrimental to the achievement of the NEO and not constitute the NEO preferable decision.

In its revised regulatory proposal, by contrast, ActewAGL Distribution proposes sustainable opex allowances, with the result that a final decision on the basis of that revised proposal would result in sustainably low prices and the maintenance of consumers' long term interests with respect to reliability, security and safety. It follows that such a decision is to be preferred to the draft decision in making a contribution to the NEO.

2.7.2 AER's draft decision does not reflect realistic expectation of required expenditure

The AER's draft decision proposes to reduce ActewAGL Distribution's opex to levels not seen since before 1999 and a capex allowance akin to that last seen in 2007/08, despite an approximate 40 per cent increase in customer numbers, and close to a 40 per cent increase in new assets new assets that now form part of ActewAGL Distribution's electricity network. These higher measures of output over the same period necessitate a higher level of opex to provide a safe, reliable and secure supply of electricity.

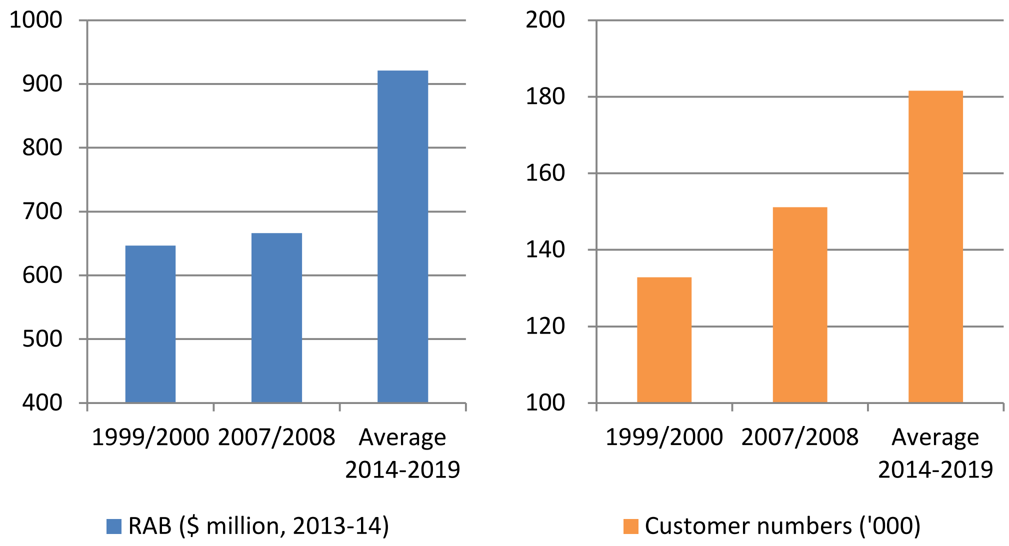
The AER's draft decision for standard control services is set in historical context in Table 2.5 and illustrated in Figure 2.2.

Table 2.5 Historical comparison of opex and capex allowances against the AER's draft decision

Standard control	ActewAGL Distribution's proposal 2014-19	AER's draft decision, 2014-19	Lowest allowance since
Opex*	$75.5m/annum	$44.1/annum	Before 1999
Capex	$74.6m/annum	$54.3/annum	2007/08

**this excludes FiT, UNFT and the Energy Industry Levy ($2013-14)*

Figure 2.2 Growth in RAB and Customer numbers



ActewAGL Distribution cannot fathom how the AER can expect it to deliver safe, secure, reliable and quality electricity distribution services with a 42 per cent reduction in its opex allowance and a resultant allowance set at levels experienced over 15 years ago, in circumstances where there has been an increase in scale, in terms of assets to maintain and customers to service, of approximately 40 per cent.

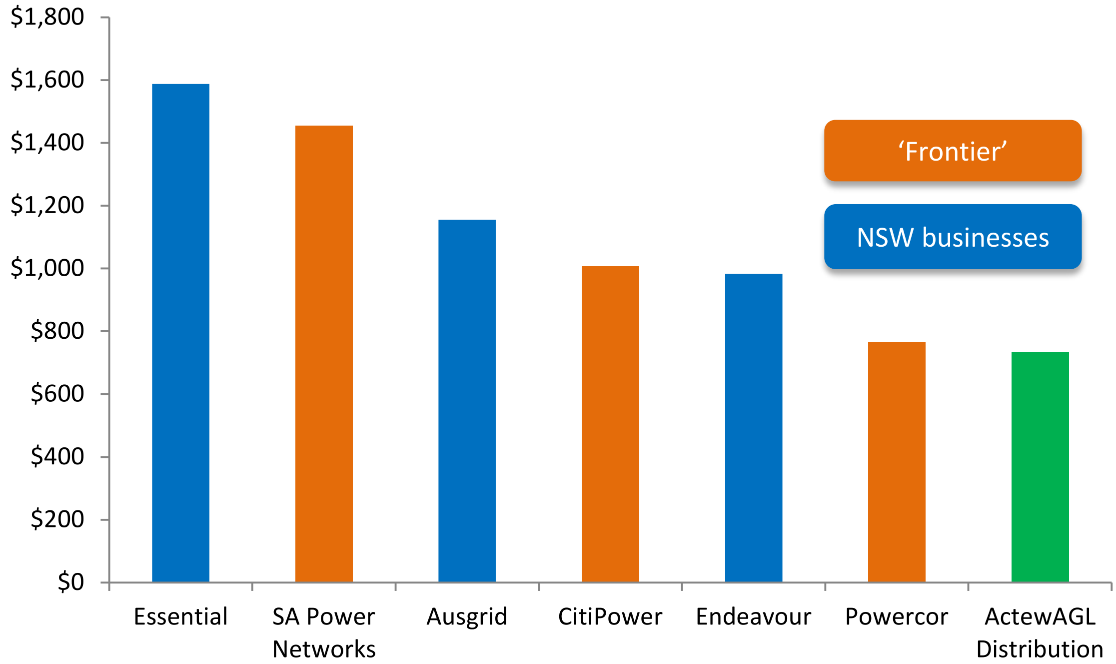
During this period, there have been five regulatory reviews and the AER is now apparently exercising its discretion as if past decisions may have been made in error.

Against this background, ActewAGL Distribution submits that the expenditure allowances proposed in the draft decision do not reflect a realistic expectation of the expenditure required to achieve the opex and capex objectives specified in clauses 6.5.6(a) and 6.5.7(a) respectively of the Rules, as is required by clauses 6.5.6(c) and 6.12.1(4)(ii) and clauses 6.5.7(c) and 6.12.1(3)(ii) respectively of the Rules.

The AER's draft decision on opex allowances in particular cannot be reconciled with the factual realities of ActewAGL Distribution's historical network pricing and reliability performance relative to that of other DNSPs, again suggesting that the expenditure allowances proposed in the draft decision do not reflect a realistic expectation of the expenditure required to achieve the opex and capex objectives. ActewAGL Distribution consistently outperforms other Australian DNSPs in terms of reliability, price and customer satisfaction.

In terms of price, ActewAGL Distribution's network charges for residential customers are the lowest in the country. In some cases, ActewAGL Distribution's customers are paying less than half what the customers of other DNSPs, including DNSPs deemed to be at the frontier of efficiency defined by the AER, are paying for their electricity distribution services. This is illustrated in the Figure 2.3 below.

Figure 2.3 Comparisons of residential network charges for residential customer consuming 7,000 kWh pa in 2014/15 (incl GST)



Note: All prices include DUOS, TUOS and metering. GST inclusive. Source: Distribution network business websites and AAD analysis

The opex reductions being proposed by the AER by relaying on its benchmarking results cannot be reconciled with ActewAGL Distribution's contention that it has the lowest tariffs for residential customers in Australia. These contentions were presented at the AER's pre-determination conference on 9 December 2014.

During this conference, the AER stated that that despite this pricing evidence, ActewAGL Distribution's business tariffs were relatively high. Despite extensive research for public available information that compares prices for business or commercial customers, ActewAGL Distribution cannot locate any recent comparison of Australian business tariffs nor has the AER provided any analysis or evidence that supports this claim.

ActewAGL Distribution notes that pricing comparisons for business customers are significantly more challenging than those for residential customers. This is due to differences in customer load profiles, the DNSP customer composition and the tariff suite offered. Regardless, to appreciate the full value of any DNSP's tariff structure a range of factors needs to be taken into account.

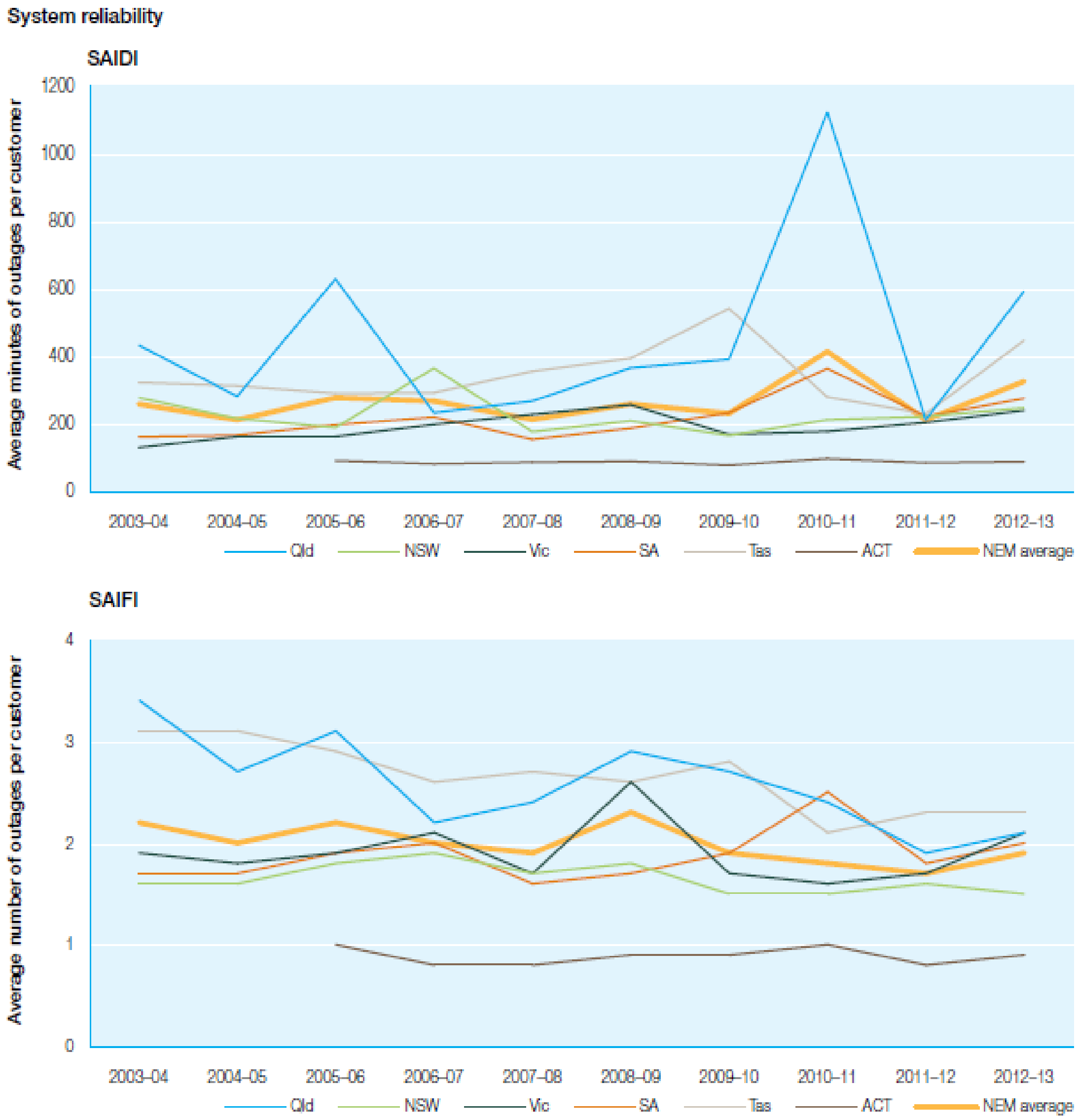
For example, ActewAGL Distribution's non-domestic customers are able to select the network that best meets their needs whereas other DNSPs constrain or determine which tariff applies. So comparisons need to take in account that although a tariff may be cheaper it may not be available to all customers. ActewAGL Distribution measures maximum demands on a 30 minute basis whilst other DNSPs use instantaneous maximum demand.

Without consideration of each of these factors, an understanding the comparison of the price and value provided to customers cannot be achieved.

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 AER shows the performance of ActewAGL Distribution against other jurisdictions in Figure 2.4 reproduced from its State of the Energy Market report for 2014.[86]

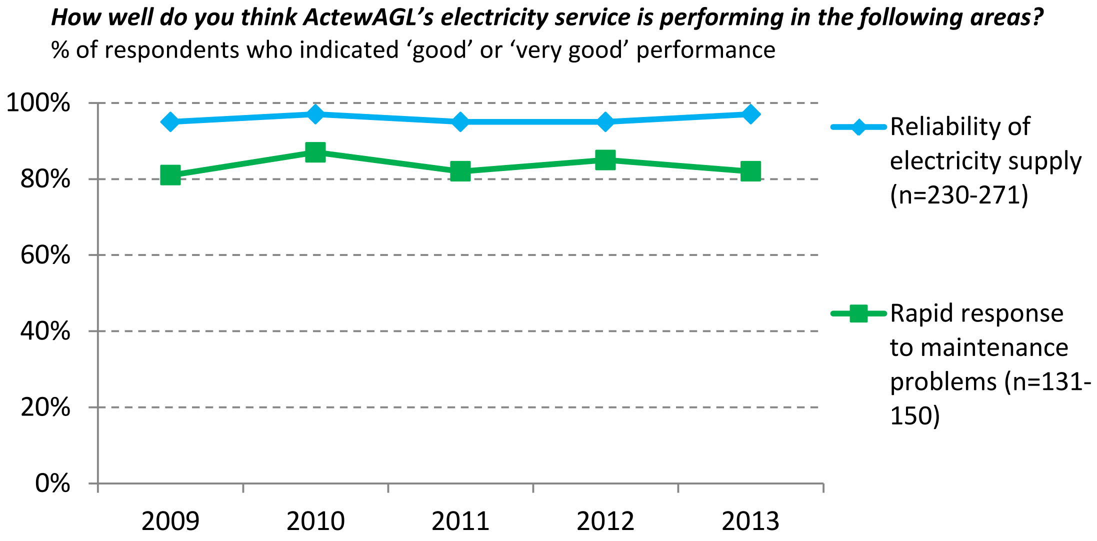
[86] AER, State of the Energy Market, 2014.

Figure 2.4 System reliability performance: SAIDI and SAIFI



Lastly, ActewAGL Distribution delivers high rates of customer satisfaction as shown below.

Figure 2.5 Responses to customer service questions



Source: Orima Research, ActewAGL Core Services Survey 2013

In summary, the contrast between:

- historical expenditure allowances, as compared to those proposed by the AER in the draft decision, and the growth in ActewAGL Distribution's network and customer numbers of the same period; and
- the proposed reduction in expenditure allowances and ActewAGL Distribution's relative performance in respect of network pricing and reliability,

indicates that the expenditure allowances proposed in the draft decision do not reflect a realistic expectation of the expenditure required to achieve the opex and capex objectives and the benchmarking analysis on which those expenditure allowances are so heavily based requires careful re-examination. As discussed at length in Chapter 3, ActewAGL Distribution considers this benchmarking analysis is fundamentally flawed.

2.7.3 Likely business model inherent in the AER's draft decision

If the AER's final decision reflects the expenditure allowances proposed in the draft decision, ActewAGL Distribution would have to transition to lower levels of expenditure by effecting drastic cost cuts within an injudicious period of time This would increase the risk profile of the business and, as ActewAGL Distribution contends in Chapter 8 of this revised regulatory proposal, likely to increase the systematic risk for the industry and requires compensation via an increase in the equity beta.

ActewAGL Distribution would have no choice but to adopt such an approach given the retrospective nature of the AER's final decision and the financial losses ActewAGL Distribution would incur, in the absence of a transition to lower levels of expenditure.

To work within approved expenditure allowances, ActewAGL Distribution would have to quickly adopt a fundamentally different business model: a "care and maintenance model". This means that current activities would be scaled back to the provision of essential business activities only, which are required to maintain network reliability and public safety.

Operating such a business model is expected to have significant impacts on ActewAGL Distribution's current service levels, reliability and safety. The likely consequences on service levels and safety are covered in section 2.7.3 below.

ActewAGL Distribution has analysed the impact to the business using a bottom-up approach based on the following steps:

1. Resources for Service Delivery and other operational field type resources are derived using the proposed Program of Works (PoW)
2. Support Staff are proportionately scaled back to align with the proposed PoW.
3. Based on steps 1 and 2, a new organisation would be developed
4. A further assessment of what roles and responsibilities could then be combined to maximise efficiencies.
5. Evaluate reductions in support staff and management.
6. Assess reductions to Support Staff and both Branch and Section Managers.
7. Estimate level of corporate services and to be provided, and associated corporate staff levels, under the care and maintenance model.

ActewAGL Distribution estimates that this would lead to about [cic [redacted]], and total restructuring costs are estimated at [cic [redacted]].

The costs of the required restructuring programme are currently unfunded in the regulatory allowances proposed by the draft decision. However, in an industry recognised as a largely fixed cost business, the costs of moving to a theoretical efficient opex level determined by the AER should commensurately be funded through the expenditure allowances determined by the AER.

The impact for ActewAGL Distribution's employees arising from these staff reductions under the "care and maintenance" model, required to meet the proposed expenditure cuts by the AER, represents the initiation of a significant organisational change and redundancy program.

The consultation provisions of the Enterprise Agreement (EA) specify a series of key minimum requirements to be followed. As such, a Workplace Relations plan has been developed to manage the timeline and people related risks associated with the proposals outlined above.

[cic [redacted]

Even if it were practicable (having regard to safety, quality, security of supply, and reliability considerations) for ActewAGL Distribution to reduce its opex to the extent required by the opex allowances proposed in the AER's draft decision, effecting significant cost rationalisation initiatives takes considerable time, rather than as one step change. There is considerable cross-sector knowledge that demonstrates that transformation is a process, not an event.

ActewAGL Distribution draws on examples provided by leading strategy consulting firms and academics in support of this view.

Box 2.1 Process and Time for Major Transformations

Kotter (2007) argues that many major change initiatives fail miserably because managers do not realize transformation is a process, not an event. It advances through stages that build on each other, and it takes years to complete. He states that many managers are pressured to accelerate the process, which causes them to skip stages, but these shortcuts never work. Kotter sets out the different stages of change – and the pitfalls unique to each stage – in order to boost a company's chances for a successful transformation:

> *"The most general lesson to be learned from the more successful cases is that the change process goes through a series of phases that, in total, usually require a considerable length of time. Skipping steps creates only the illusion of speed and never produces a satisfying result." "Real transformation takes time, and a renewal effort risks losing momentum if there are no short-term goals to meet and celebrate. Most people won't go on the long march unless they see compelling evidence in 12 to 24 months that the journey is producing expected results. Without short-term wins, too many people give up or actively join the ranks of those people who have been resisting change." (See Attachment B5,* John Kotter, *Leading Change – Why Transformation Efforts Fail*, Harvard Business Review, 1995 (republished in Best of HBR, January 2007)

McKinsey & Company (2011) explain the various stages of effecting major organisational transformations effectively. The article promotes a system of 5A's being: Aspire, Assess, Architect, Act and Advance. The fourth step (Act) relates to managing the transformation process. The authors suggest that an effective management process is likely to take several years:

> *"To keep energy levels high through the long haul of implementation, make sure everyone understand how their contribution fits into the big picture. A powerful way to do this is to structure the program at three levels: a transformation headline that sums up your aspiration and the rationale behind it, a few broad performance and health themes that typically run for two to three years, and the specific initiatives that further these themes, each taking a few months or so to complete" (See Attachment B6,* McKinsey & Company, *Insights into Organisation – How do I Transform my Organization's Performance*, June 2011)

Bain establishes characteristics of successful transformations tracked by Bain. The second of these characteristics is that the organisations 'tackle the transformation one chunk at a time.'

> *"Even though they have to move swiftly within a narrow window, successful leaders do not take off in a dozen directions simultaneously. They realise that they cannot replace top management, and simplify processes, and overhaul communication, all at once."* (See Attachment B7, Bain & Company, *Company Transformation – More a Science than an Art*, Undated)

Therefore, ActewAGL Distribution does not believe that it is either efficient or prudent to attempt to transform the business model and expenditures within one regulatory control period. Otherwise, any short-term reductions will result in long-term damage. Furthermore, the damage– to the business, the network, quality of service and security of supply – would have to be repaired in due course, with the resultant potential for higher whole-of-life cost.

This would not serve the long term interests of consumers and a decision that delivers such an outcome could not be said to be a NEO preferable decision.

As a result, in Chapter 3 of this revised regulatory proposal, ActewAGL Distribution proposes the establishment for a glide path to a new lower level of expenditure. Even where such a glide path is established, however, the effects of the AER's proposed expenditure allowances (including those on reliability, security and safety discussed in section 2.7.4 below) are such that a final decision giving effect to those allowances could not be said to contribute to the achievement of the NEO or constitute NEO preferable decision.

2.7.4 Likely consequent effects of draft decision on reliability, security and safety

Against the background of the implications of the draft decision for the operation of ActewAGL Distribution's business discussed above, ActewAGL Distribution considers that the AER's draft decision on opex and capex will have potentially dire consequences for the reliability, security and safety of supply, and the reliability, safety and security of the distribution system, for consumers in the ACT.

In response to a question from stakeholders[87] on how the AER has assessed ActewAGL Distribution's ability to meet safety and reliability standards, the AER responded that it had not directly tested this. Instead, the AER noted that this was addressed by implication by the benchmarking analysis because, if "frontier" firms can meet safety and reliability standards with the benchmarked levels of opex, then ActewAGL Distribution should also be able to do so.

The AER's response was that the proposed expenditure allowance is sufficient for the frontier firm is based on a false premise that its benchmarking analysis can be relied upon, and adequately takes into account the environmental factors that affect ActewAGL Distribution's costs. The inadequacy of the benchmarking, and the fact that the AER cannot observe the efficient expenditure level from the analysis therefore undermines the validity of its reasoning and conclusion.

It is evident from the AER's draft decision that it has not conducted any risk assessment of the proposed expenditure cuts on safety, security and reliability of supply, and safety, security and reliability of the distribution system. ActewAGL Distribution submits that the AER needs to carry out a detailed engineering review, and a comprehensive risk assessment of its decision, if it is to be satisfied that a final decision based on the draft decision is to be preferred in making the greatest contribution to the achievement of the NEO (as required by section 16(1)(d) of the NEL).

ActewAGL Distribution draws on external advice from AECOM[88] to substantiate its contention that the proposed expenditure allowances would have potentially dire consequences for the

[87] AER pre-determination conference, Canberra 9 December 2014.

[88] See Attachment B8. AECOM, *The Impact of the AER's Draft Decision on ActewAGL's Service and Safety Performance*, January 2015

reliability, security and safety of supply, and the reliability, safety and security of the distribution system, for consumers in the ACT. In order to provide this advice, AECOM have reviewed how work management is prioritised and managed by ActewAGL Distribution.

In contrast, the AER relied on limited engineering reviews done by its own staff, did not carry out any site visits to ActewAGL Distribution and set expenditure allowances using desk-top analysis and REPEX models that are flawed (see Chapter 3 for more details on a critique of the AER's opex benchmarking analysis, and Chapter 4 for more details on a critique of the AER's capex modelling). AECOM's report concludes that:[89]

> *A forced reduction in REPEX and OPEX of the scale suggested by the AER would have a significant impact on the level of service ActewAGL is able to provide to its customers, potentially including an impact on safety levels associated with its* assets. (Executive Summary, page i).

This overall conclusion is supported by a number of analyses and observations including with respect to:

- the principle of lowest mean annual cost of delivery;
- the impact of reduced replacement capex;
- the impact of capex reductions on opex requirements;
- the impact of opex reductions on levels of service; and
- the impact of opex reductions on safety levels.

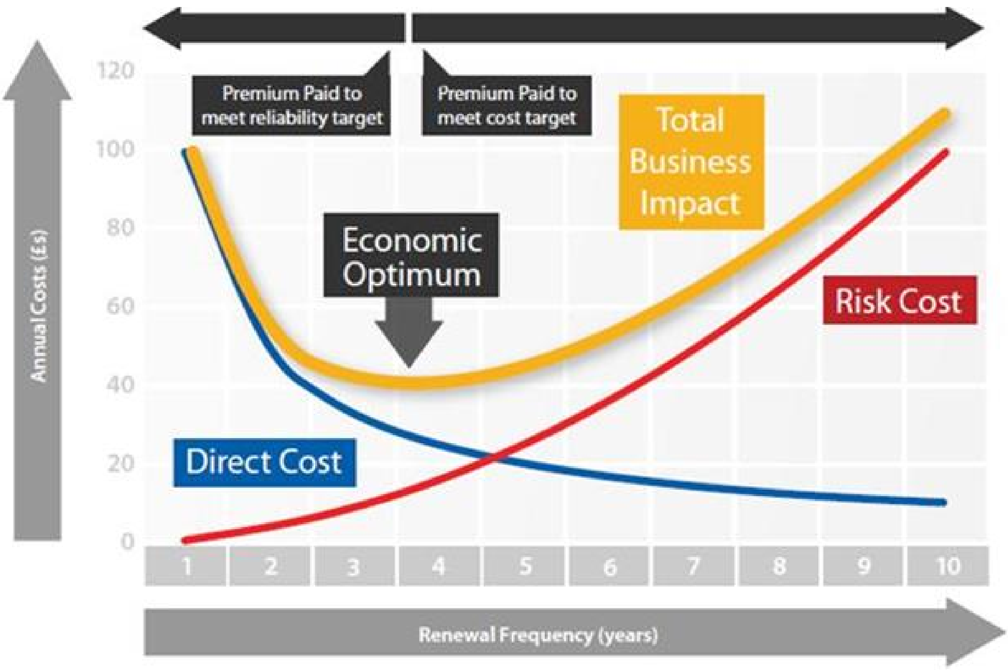
These analyses are discussed further below.

[89] See Attachment B8. AECOM, *The Impact of the AER's Draft Decision on ActewAGL's Service and Safety Performance*, January 2015.

Lowest mean annual cost of delivery

AECOM explains the principle of achieving the lowest whole-of life cost as follows:

> *The principle involved in achieving the lowest whole-of-life cost is illustrated in Figure 1 [below], which shows the mean total annual cost as a yellow line, the contributory direct costs (blue) and cost of service interruption (red). The lowest mean annual cost is the 'economic optimum' for a critical asset. Cost premiums could be applied to meet higher reliability targets (higher levels of service) or as a higher cost of risk (lower levels of service*).



ActewAGL optimises its costs by balancing intervention (maintenance) costs with asset risk over the lifetime of the asset. The value of risk that accrues to a given asset escalates every year as the asset ages and deteriorates. Eventually the annual cost of risk is high enough to warrant the REPEX required to replace the asset and therefore reduce the risk cost to the level it would be for a new asset.

A software tool (Riva) is used to determine the optimal combination of replacement, refurbishment and inspection costs that enables the asset to deliver acceptable levels of service over its life, and therefore identify the strategy that provides the least mean annual cost.

The timing of renewal can be deliberately scheduled away from the economic optimum:

- *Early renewal can be scheduled for risk reasons, generally for critical assets that should not be allowed to fail, where the total cost of ownership is accepted as being higher* *than the least cost for strategic (risk) reasons. In practice, this strategy involves a cost premium being paid to achieve a higher reliability target.*

- *Late replacement can be done for budget reasons, where renewal is delayed past the point that represents the least cost timing because funds are not available for the asset concerned at the time required (the asset is a low priority). The risk cost includes:*
  - *higher than optimal intervention costs (unplanned replacement generally comes at a higher cost than when planned)*
  - *higher maintenance costs (a higher rate of inspections, more frequent temporary repairs and costs associated with repairs and other interventions that would not have been necessary if the assets were renewed at the optimal time)*
  - *the cost to customers (and ActewAGL) of service interruptions.*

In practice, a late replacement policy for a critical asset implies a devaluation of the value of the service and an increase in the cost of interruptions for customers and ActewAGL…

A reduction in funds available for management of ActewAGL's assets, whether capital for renewal or operational for maintenance and emergency management, will force an increase in the tolerance for risk by ActewAGL (and its customers), and reduce the level of service able to be delivered. [90]

<u>Impact of reduced repex</u>

AECOM states that the effect of a reduced repex budget is to defer asset replacement or renewal. AECOM notes that:

The impact of an extended deferral of asset replacement will be:

- *a steadily increasing rate of service interruptions*
- *often a decrease in public safety*
- *an increase in the backlog of unfunded works*
- *an increase in future service costs…*

In particular, AECOM assesses the impact of reduced repex on underground cables and opines that:

[90] See Attachment B8. AECOM, *The Impact of the AER's Draft Decision on ActewAGL's Service and Safety Performance*, January 2015 page 4 to 6

ActewAGL's actual experience with its cables enables standardised deterioration curves to be adapted based on specific conditions and experience in the ACT, and this has been used to derive the underground cable REPEX projections included in ActewAGL's submission.

The AER, in contrast, has derived theoretical remaining lives for these cables in its calibrated model that are more than double ActewAGL's assessment (for underground cables rated up to 11kV), which significantly affects REPEX budget projections.

If the AER's determination prevails and their life estimates are proven incorrect, there will be a significant increase in service interruptions caused by cable failures….

The increased risk associated with funding constraints also means that average asset condition will deteriorate more in the future than would otherwise be the case. The effect will be that current consumers will have their cost of service reduced, but future consumers will have to pay more (to replace badly deteriorated assets) while receiving an inferior level of service compared to current consumers…

A reduction in funds available would force a delay in the renewal program, therefore increasing the risk of service interruption for those customers involved. The significant reduction proposed by the AER would substantially increase the risk of service interruption faced by ActewAGL's customers…

Customers unable to accept a decline in level of service or an increased risk of service interruption will have to invest in contingency measures. The forced reduction in funding will therefore increase supply costs for some customers, and force the remainder to accept a lower level of service. [91]

<u>Impact of capex reductions on opex requirements</u>

AECOM further assesses the impact of capex reductions on opex requirements. For example, AECOM note:

A forced delay in ActewAGL's renewal program will force an increase in the risk of failure and an increase in maintenance and repair costs. Unplanned interventions come at a significantly higher cost to the service provider, and often at a higher cost to both the customers affected and ActewAGL…

A number of comparisons of strategic alternatives have been provided by ActewAGL to the AER in its submissions, generally to demonstrate cost optimisation or prioritisation. Figure 3 in this report is one of those, using underground cables:

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[91] See Attachment B8. AECOM, *The Impact of the AER's Draft Decision on ActewAGL's Service and Safety Performance*, January 2015 page 15 to 16

- *The optimal strategy is shown to be selective cable replacement (rather than reactive repair work), a strategy that was estimated to be 56% of the cost of the 'do nothing' option.*
- *If REPEX funding were not to be available, then the higher cost option (using OPEX) would have to be followed, increasing the total cost of ownership of the assets involved by an estimated 78%.*
- *If the OPEX required were also not available, ActewAGL would be faced with an unacceptable long-term loss of service to customers affected by cable failures, or a need to transfer funds from another lower priority application (thereby potentially forcing other customers to deal with loss of service).* [92]

Impact of opex reductions on levels of service

Using data provided by ActewAGL Distribution, AECOM assess that a 42 per cent reduction is opex is likely to lead to:

- ***An increased response time****, to more than double current performance, therefore increasing the total customer minutes of service interruption and delivering a reduction in level of service.*
- ***A reduction in ActewAGL's ability to carry out planned maintenance*** *by more than 33%.*
- ***A vicious cycle of increasing numbers of unplanned faults because planned maintenance would not be carried out, causing further increases to response times.***

If renewal capital budgets are reduced, and operational budgets also reduced to the extent determined by AER, the impact will be far more dramatic.

ActewAGL will be faced with aging assets failing more frequently, an inability to carry out planned maintenance, and steadily worsening response times. The cumulative impact will be a drastically lower level of service for customers. [93]

Furthermore, ActewAGL Distribution contends that the opex and capex cuts proposed in the AER's draft decision correspond to a level of reliability that would:

[92] See Attachment B8. AECOM, *The Impact of the AER's Draft Decision on ActewAGL's Service and Safety Performance*, January 2015 page 18

[93] See Attachment B8. AECOM, *The Impact of the AER's Draft Decision on ActewAGL's Service and Safety Performance*, January 2015, page 20 to 21

- be in breach of ActewAGL Distribution's obligations under the Supply Standards Code; and
- would incur penalties under STPIS.

These cuts are inconsistent with Section 7A(2) of the NEL, since the resultant expenditure allowances do not provide "a reasonable opportunity to recover at least the efficient costs the operator incurs in… complying with a regulatory obligation." They are also inconsistent with the opex and capex objectives in clauses 6.5.6(a)(2) and 6.5.7(a)(2) respectively of the Rules to "comply with all applicable regulatory obligations or requirements associated with the provision of standard control services."

On more than one occasion in its draft decision, the AER elects to quote stakeholder opinions that customers would prefer poorer network reliability at a corresponding lower price.[94] Regulatory obligations in relation to reliability are set by the ACT Government in the Supply Standards Code and do not represent a constituent decision under the AER's determination. Accordingly, the appropriate response by the AER to such statements in stakeholder submissions would be to simply note that assessments of potential changes to regulatory obligations in relation to reliability are outside the scope of the AER determination. The fact that the AER elects to highlight these opinions in its draft decision suggests the AER is entertaining the question of whether regulatory obligations are appropriate and a willingness to put at risk ActewAGL Distribution's ability to meet its regulatory obligations in relation to reliability.

<u>Impact of opex reductions on safety levels</u>

ActewAGL Distribution has a duty of care under the WHS Act 2011 and meet safety requirements under the Utilities Act 2000 (ACT). AECOM's reports states that:

> *The Utilities Act 2000 (ACT) imposes specific technical, safety and reliability obligations (Section 5.3), and the NER v66 specifies factors that must be considered in relation to capital expenditure, including safety and security of supply.*
>
> *Section 4 in Part 5 of the Utilities Act provides that the obligation does not apply if:*
>
> 1) *The events or conditions are outside the control of the electricity distributor and prevent the electricity distributor from complying with this Code; and*
> 2) *The consequences of the events or conditions are not due to the electricity distributor's actions or lack of actions.*

[94] AER 2014, Draft decision – ActewAGL distribution determination 2015-16 to 2018-19, p. 66-67, p. 11-18.

The implication is that, if ActewAGL can be shown to have been prevented from undertaking necessary preventive action by a third party, the obligation and potential liability could be placed with that party….

There are many safety issues considered in the planning of ActewAGL's REPEX program. These would be affected by the significant budget cuts proposed by the AER:

The low voltage cast iron pothead replacement program, required to reduce safety risk for our workers and the public from explosive failures (Figure 17)[below cic].

[redacted]

- *Failure of pole-top hardware and cross-arms is the most common form of failure on the overhead distribution system, causing overhead conductors to sag excessively or fall to the ground. The risk to public and worker safety can be significant in such an event.*
- *Replacement of deteriorating cross-arms and pole-top hardware, and installation of vibration dampers, armour rods, and preformed distribution ties on rural high voltage overhead lines located in high bushfire risk areas is required to minimise the role that*

these assets can play in starting bushfires which are a significant threat to life and property (refer to Figure 18).[95]

2.8 Procedural fairness

2.8.1 Overview

In this section, ActewAGL Distribution sets out its contentions in support of the proposition that ActewAGL Distribution was denied a reasonable opportunity to make submissions on the determination in responding to the draft decision in breach of the AER's procedural obligations. ActewAGL Distribution contends that the AER's breach of its procedural obligations in respect of the draft decision, by hindering meaningful scrutiny and submission on that Decision, renders it less likely that its final decision will contribute to the achievement of the NEO.

2.8.2 Legal context

Under section 16(1)(b) of the NEL, the AER must, in performing or exercising any function or power that relates to the making of a distribution determination, ensure that the regulated network service provider to whom the determination will apply (here, ActewAGL Distribution) is, in accordance with the Rules, informed of material issues under consideration by the AER and given a reasonable opportunity to make submissions in respect of the determination before it is made.

Even if section 16(1)(b) of the NEL was qualified in the manner for which the AER has on occasion contended, the AER would have a common law obligation to consult on any material change in its analysis before relying on that analysis in its final decision. A failure to consult in those circumstances would likely constitute a breach of its common law obligation to accord procedural fairness and render its final decision not in accordance with law.

2.8.3 Summary of ActewAGL's contentions on procedural fairness

ActewAGL Distribution contends that, in order to discharge its obligation to provide ActewAGL Distribution with a reasonable opportunity to make submissions in respect of the determination before it is made in accordance with the AER's obligation under section 16(1)(b) of the NEL and its common law obligation to accord procedural fairness through publication of and consultation on the draft decision, the AER was required to provide ActewAGL Distribution with the information, reports, models, data and other material on which the AER relied in reaching its conclusions in, and making, the draft decision.

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[95] See Attachment B8. AECOM, *The Impact of the AER's Draft Decision on ActewAGL's Service and Safety Performance*, January 2015, page 22

Without access to this material, ActewAGL Distribution is unable to fully and properly understand the AER's reasoning and conclusions, cannot properly scrutinise and assess the basis for those conclusions and, accordingly, cannot meaningfully respond to that reasoning and those conclusions.

In order for ActewAGL to be accorded a meaningful opportunity to be heard on the draft decision, therefore, ActewAGL Distribution requested all relevant information, reports, model, data and any other material relevant to the draft decision.[96]

Despite reassurances by the AER that all relevant information would be provided at the time the draft decision was released,[97] it became apparent that there were gaps in the information that ActewAGL Distribution was provided with by the AER at the time of publication of the draft decision, which it needed if it was to properly review and evaluate the reasoning and conclusions of the AER in that Decision in preparing its revised regulatory proposal. A further request was made by ActewAGL Distribution to the AER on 5 December 2014 and a response provided by email on 10 December 2014.[98]

This delay in the provision of the material on which the AER relied in making its draft decision materially prejudiced the preparation of ActewAGL Distribution's revised regulatory proposal. It reduced the (already limited) time afforded to ActewAGL Distribution under the Rules to prepare its revised regulatory proposal and respond, in particular, to the significant, unanticipated change in the AER's regulatory approach to forecasting opex (which unanticipated change of regulatory approach it was the object of the Better Regulation program required by the AEMC's 2012 Rule amendments to avoid).

In Table 2.6 ActewAGL distribution summarises the relevant aspects of its regulatory proposal and the AER’s draft decision, and its contentions in support of the proposition that ActewAGL Distribution was denied a reasonable opportunity to make submissions on the determination in responding to the draft decision in breach of the AER's procedural obligations and to the detriment of the achievement of the NEO.

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[96] Letter from David Graham, Director, Regulatory Affairs and Pricing at ActewAGL Distribution to Mr Warwick Anderson, General Manager Network Regulation of the AER dated 19 November 2014.

[97] Letter from Michelle Groves, CEO, AER to David Graham, Director, Regulatory Affairs and Pricing at ActewAGL Distribution dated 20 November 2014

[98] Letter from Usman Saadat, Manager Regulatory Affairs of ActewAGL Distribution to Mr Warwick Anderson, General Manager Network Regulation of the AER dated 5 December 2014 and email of response from Kurt Stevens of the AER to Bjorn Tibell, Senior Financial Advisor of ActewAGL Distribution dated 10 December 2014.

Table 2.6. Summary of procedural issues in the AER's decision making

Opex	• The AER has not complied with the procedural requirements of the NER and has denied ActewAGL Distribution an opportunity to provide comment on the AER's benchmarking techniques in advance of publication of the draft decision. ActewAGL Distribution submits that the AER's Annual Benchmarking Report neither disclosed the economic benchmarking techniques or analysis on which the AER relies in its draft decision, nor was that Report published by the deadline stipulated by the NER. As a consequence, ActewAGL Distribution has been denied the opportunity to be heard on the development of those techniques and that analysis in advance of publication of the draft decision. • It is apparent that the AER did not pro-actively take the necessary steps to engage with the ACT's Technical and Safety Regulators about relevant technical and safety obligations. ActewAGL Distribution enquiries indicate that it is unlikely that that the ACT's Technical and Safety Regulator made any submission to the AER on the Draft Annual Benchmarking Report and the AER was obscure when challenged on its consultation process. • The AER provided embargoed version of documents on notice(under notice from ActewAGL Distribution by way of letter dated 17 November 2014) • The AER changed its preferred benchmarking methodology after it had consulted with DNSPS on a draft annual benchmarking report. This is covered further in Chapter 3. • The AER is unable to provide additional information requested that would further ActewAGL Distribution's ability to assess all the necessary information prior to submitting its revised regulatory proposal. This included: – Vegetation management costs for all DNSPS; – Deloitte, NSW Distribution Network Service Providers Labour Analysis. This is cited, for example, at footnotes 153 and 154 of Attachment 7 to the draft decision.
Capex	• The AER undertook a limited scope internal engineering review of ActewAGL Distribution's major augex and repex projects and programs. • The AER did not provide any reports relating to its internal engineering review of ActewAGL Distribution's major augex and capex projects and programs. • In applying a capitalised overhead adjustment factor of 2.75% based on the

	historical trend over the past five years, the AER has not taken into account the change in ActewAGL Distribution's cost allocation model (CAM) which was approved by the AER in June 2013 and came into effect on 1 July 2014. • At a meeting with ActewAGL Distribution staff on 18 December 2014, the AER stated that it had 'assumed that what ActewAGL Distribution is allocating to capex and opex has remained the same' because 'nothing in the regulatory proposal demonstrated a change in capitalisation.' ActewAGL Distribution has not changed its capitalisation policy. An explanation of the CAM change and its impact on capitalised overheads had previously been provided in ActewAGL Distribution's 3 October 2014 response to the AER's information request of 17 September 2014 (capex) and 23 September 2014 (opex). • The AER's consolidated capex model contains figures that are inconsistent with the AER's draft decision in respect of each capex category. In a meeting with ActewAGL Distribution staff on 18 December 2014, the AER stated that it had applied the 'same [percentage reduction] factor across the system' rather than doing a 'bottom up build model.' This is not consistent with the approach referenced in the draft decision which was to 'make reductions…to projects.'[99] • The AER also acknowledged a 'lack of clarity' around ActewAGL Distribution's non-network capex forecasts at the 18 December 2014 meeting with ActewAGL Distribution staff. The AER stated it would 'ideally would have done an information request, but in the interest of time frames, didn't.'
Demand and consumption forecasts	• Failed to provide any written econometric advice received by the AER from external advisors

ActewAGL Distribution does not consider that the AER's conduct in publishing and consulting on the draft decision complies with its procedural requirements and detracts therefore from the achievement of the NEO.

[99] For example, in the AER's discussion on augex, page 6-31 the AER states "Based on this engineering review, we made reductions to the following projects…."

3 Operating expenditure

3.1 Introduction and overview

In this Chapter, ActewAGL Distribution submits that the AER's draft decision on operating expenditure (opex) is not in accordance with law, involves a material error, or material errors, of fact and/or an incorrect exercise of discretion.

Therefore, the AER's draft decision on opex does not contribute to the achievement of the NEO and, thus, does not result in a draft decision on opex or an overall draft decision that contributes to the achievement of the NEO to the greatest degree as required by Section 16(2)(d) of the NEL.

The AER's draft decision is detrimental to the long term interests of consumers. If implemented, the draft decision will adversely impact the ability of ActewAGL Distribution to provide safe, reliable and secure supply at an efficient price.

In determining an unrealistic, reckless and unsustainably low opex allowance, the AER has not complied with the procedural requirements of the Rules and has denied ActewAGL Distribution procedural fairness.

The AER has acted contrary to the scheme of the Rules by failing to rely on ActewAGL Distribution's proposal as the basis for its considerations. Instead, the AER has incorrectly exercised its discretion by placing primacy on the outcomes of its benchmarking analysis and determining a substitute opex allowance. The economic benchmarking analysis in the most recent annual benchmarking report is just one of a number of opex factors and benchmarking analysis is not a substitute for the role of ActewAGL Distribution's proposal.

Expert reports commissioned by ActewAGL Distribution demonstrate in no uncertain terms that the AER's benchmarking analysis is, however, fundamentally flawed and cannot be relied on to set opex allowances. The Australian data set upon which the model draws is internally inconsistent, with the inclusion of international data exacerbating this problem.

The econometric model adopted by the AER is neither sufficiently robust nor does it properly take account of justifiable and important environmental variables. All unexplained differences in the AER's benchmarking results are considered as inefficiency compared to "frontier" firms. This is a gross simplification and an error. For example, ActewAGL Distribution has identified that the AER fails to understand that ActewAGL Distribution must operate and maintain, relative to the Victorian urban Distribution Network Service Providers (DNSPs):

- 36% more sub transmission lines;
- 40% more zone substation transformer capacity;

- 108% more 11kV-33kV distribution lines;
- 32% more distribution transformer capacity; and,
- 38% more low voltage line.
- 41% more poles per customer;
- 20% more route length per customer for an equivalent circuit length;
- 36% more overhead line length per customer.

Additionally, in an attempt to compensate for the lack of environmental variables, the AER applies a series of *ad-hoc* post-modelling modelling adjustments. However, these adjustments do not offset the need for a reliable data set and, regardless, have been calculated incorrectly. The AER's benchmarking analysis and result is therefore an example of 'garbage in – garbage out' modelling.

In its mechanistic application of benchmarking, the AER has also retrospectively abandoned its efficiency benefit sharing scheme (EBSS) and the use of a revealed cost approach to identifying efficient base year expenditure. In doing so, the AER has destroyed a key pillar of the incentive regime which breaches the regulatory contract, resulting in large financial losses, and increases in regulatory risk and unpredictability.

ActewAGL Distribution rejects the AER's draft decision and submits that the use of a revealed cost approach, in conjunction with an appropriate rate of change and step changes, is a superior approach to determining the opex allowance. ActewAGL Distribution's overarching response to the AER's draft decision and revised proposal is shown in Table 3.1. Unless otherwise specified, all financial information in this chapter is stated in real 2013/14 dollar terms.

Table 3.1 Overview of ActewAGL Distribution's response to the AER's draft decision ($ million, 2013/14)

Component	Regulatory proposal	AER's draft decision	Position on draft decision	Revised proposal
Base + zero based opex	335.4	210.0	Does not accepted	315.5
Rate of change	9.8	8.9	Does not accepted	11.6
Step change	35.3	1.4	Does not accepted	44.1
Total	377.3	220.3	Does not accepted	371.2

In its regulatory proposal, ActewAGL Distribution proposed total forecast standard control service opex of $377.3 million ($2013/14) for the 2014-19 period (excluding debt raising costs). This total opex forecast was comprised of:

- Base opex for the 2014/19 period of $224.7 million based on adjusted actual opex incurred in the 2012/13 revealed cost base year, excluding maintenance and vegetation management;
- Zero-based category specific forecasts for network maintenance and vegetation management expenditure of $110.7 million, including $3.1 million for real price growth and $0.4 million for output growth;
- Step changes, which resulted in an increase to base opex for the 2014/19 period of $35.3 million; and
- Forecast changes in input prices, which resulted in an increase to base opex for the 2014/19 period of $6.7 million, (not including maintenance and vegetation management, for which real price growth was incorporated into the zero-based forecast).

In its draft decision, the AER concludes that it is not satisfied ActewAGL Distribution's opex forecast reasonably reflected the opex criteria. Accordingly, the AER rejects the opex forecast included in ActewAGL Distribution's building block proposal. The AER substitutes ActewAGL Distribution's total opex forecast for the 2014-19 period with the AER's total opex forecast for that period, which it considers reasonably reflected the opex criteria.[100] The AER's draft decision represents a reduction in total opex of $157 million from that proposed by ActewAGL Distribution of $377.3 million to $220.3 million.

The AER's draft decision in respect of opex is contained in Attachment 7 to the draft decision and is summarised in the following table extracted from the AER's draft decision.[101]

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[100] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-7

[101] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-7, Table 7.1

Table 3.2 AER draft decision on total opex ($ million, 2013/14)

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
ActewAGL Distribution 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
Difference	**-34.2**	**-31.7**	**-28.9**	**-30.7**	**-31.5**	**-157.0**

In assessing ActewAGL Distribution's forecast opex, the AER has compared that forecast to its own estimate of forecast opex. As ActewAGL Distribution's forecast opex materially exceeds the AER's own estimate of forecast opex, the AER concludes that ActewAGL Distribution's proposed total forecast opex does not reasonably reflect the opex criteria and uses its own estimate as a substitute forecast.[102]

The key areas of difference between ActewAGL Distribution's forecast opex and that of the AER with respect to the starting base, rate of change and step changes are as follows:[103]

- the AER considered that ActewAGL Distribution's 2012/13 base year opex did not represent that which would be incurred by an efficient and prudent service provider and therefore substituted ActewAGL Distribution's 2012/13 base year opex of $66.8 million with its own forecast of $42.2 million, a reduction of 36.8 per cent[104];
- the AER adopted a higher rate of change than that proposed by ActewAGL Distribution due to its estimation of a higher forecast of output change, however, in dollars terms the forecast opex attributed to the rate of change in the AER's forecast is similar to that proposed by ActewAGL Distribution because the AER's higher rate of change is applied to a lower base opex.[105]

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[102] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-16

[103] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, pages 7-17 to 7-21

[104] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-19, Table 7.4 and page 7-26, Table A.1 and discussed further in Section 3.4.2

[105] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-20

- the AER considered that a step change adjustment to base opex of $1.4 million for increased costs associated with new regulatory obligations satisfied the opex criteria, as compared to ActewAGL Distribution's proposed step change adjustment of $35.3 million.

With respect to the base year opex reduction, the AER on the advice of Economic Insights Pty Ltd (Economic Insights), used the results from its preferred benchmarking model, the Cobb Douglas stochastic frontier analysis model, as the starting point for derivation of the AER's substitute base opex. It then made the following adjustments:

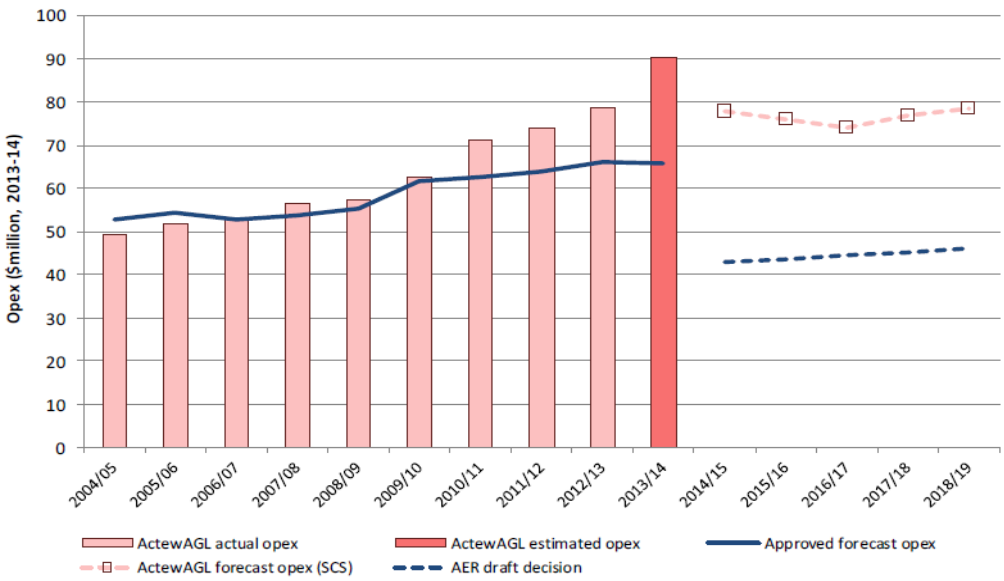
- the provision of a further 30 per cent allowance for those operating environment differences the AER conceded were not captured in its preferred benchmarking model; and
- adoption of a weighted average of all networks with efficiency scores of 0.75 (75 per cent) or above (i.e. CitiPower, Powercor, United Energy, SA Power Networks and AusNet) rather than the most efficient service provider (CitiPower) in assessing ActewAGL Distribution's efficiency.[106]

The end result of the approach is an unprecedented reduction in ActewAGL Distribution’s opex allowance. The opex allowance is lower than the forecast and actual opex in each and every year of the last two regulatory control periods, a period of 10 years. This drastic reduction can be seen in Figure 3.1, extracted from the AER's draft decision.[107]

[106] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-19

[107] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-8, Figure 7.1

Figure 3.1 AER draft decision compared to ActewAGL Distribution's past and proposed opex



Source: ActewAGL, Regulatory accounts 2004–05; ActewAGL, Economic benchmarking - Regulatory Information Notice response 2005–06 to 2012–13; ActewAGL, *Regulatory proposal for the 2014–19 period* - Regulatory Information Notice.

In this Chapter 3, ActewAGL Distribution outlines the legal and regulatory framework applicable to setting the opex allowance (in Section 3.2) and the relevant background to the AER's draft decision on opex (in Section 3.3) and then proceeds to respond to:

- the AER's detailed analysis of ActewAGL Distribution's base opex set out in Appendix A to Attachment 7 of the draft decision, in Section 3.4;
- the AER's draft decision on the opex rate of change set out in Appendix B to Attachment 7, in particular its draft decision on the price change component of the rate of change, in Section 3.5;
- the AER's draft decision on step change adjustments to base opex in Appendix C to Attachment 7, in Section 3.6; and
- the AER's draft decision on ActewAGL Distribution's forecasting methodology for determining the opex forecast for the 2014-19 period set out in Appendix D to Attachment 7, in Section 3.7.

Finally, ActewAGL Distribution addresses the imperative for establishment of a transition path, in the event that the AER is minded to make a final decision on opex that is substantively similar to its draft decision, in Section 3.8.

ActewAGL Distribution response to the AER's draft decision on debt raising costs covered in in Chapter 8.

The discussion and conclusions set out in this Chapter are supported by a four expert reports attached to this revised regulatory proposal:

- Attachment C1: HoustonKemp 2015, *Opex and the efficiency benefit sharing scheme*
- Attachment C2: Advisian 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT)*
- Attachment C3: CEPA 2015, *Benchmarking and setting efficiency targets for the Australian DNSP's: ActewAGL Distribution*
- Attachment C4: Huegin 2015 *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*

In addition to the expert reports, this Chapter is supported by other supporting information, as indicated in the text and included as attachments to the revised regulatory proposal.

3.2 The relevant legal and regulatory framework for setting the opex allowance

3.2.1 The NEO and the RPPs

The AER must perform or exercise a function or power under the NEL or the Rules that relates to the making of a distribution determination in a manner that will or is likely to contribute to the achievement of the NEO (NEL, Section 16(1)(a) and Section 2(1) definition of 'AER economic regulatory function or power'). Further, in making a distribution determination, if there are 2 or more decisions that will or are likely to contribute to the achievement of the NEO, the AER must make the decision that it is satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree (NEL, Section 16(1)(d) and Sections 2(1) and 71A definitions of 'reviewable regulatory decision').

The NEO is set out in Section 7 of the NEL and reads as follows:

> *The objective of this Law 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-*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system.*

Economic efficiency, including efficient investment in the system with which the provider provides services, is thus the ultimate objective of the regulatory regime established by the NEL and Rules. The interests of consumers of electricity with which the NEO is concerned are those in obtaining lower prices (than would otherwise be the case), increased quality, safety, reliability and security of supply and the increased reliability, safety and security of the national electricity system.[108]

The phrase 'long term' is concerned with the period over which the full effects of the AER's decision will be felt.[109] The comments of the Tribunal on the phrase 'long term' in considering the objective of Part XIC of the TPA (now the CCA), being the 'long term interests of end-users', are apposite. It relevantly observed:[110]

> *In considering how these elements may combine, it may be the case, for example, that very low prices are in the short-term interests of end-users. Over the long-term, however, sustainably low prices (which may be higher than the "very low prices" referred to above) are more likely to enhance their interests, as the long-term interests of end-users are likely to suffer in an environment characterised by short-lived operators who fall over soon after the customer signs with them, as distinct from one in which reliable service-providers offer competitive, but sustainable, services. Moves that enhance the quality and diversity of service may be subject to a similar analysis.*

The NEO is, thus, concerned with the long term interests of consumers in sustainably low prices, and the maintenance or enhancement of quality, safety, reliability and security, rather than the pursuit of price reductions in the short-term at the expense of their other interests. This has been recognised by the Tribunal in the following terms:[111]

> *As notes at the outset, customers will benefit in the long run if resources are used efficiently, ie if investors receive a return on efficient investment which covers the opportunity cost of the capital required to deliver the services. While consumers might benefit today from the lowest possible prices which do not provide an adequate return on investment, such prices are not in their long term interests… If those prices were sustained, they would not generally support the allocation of sufficient resources including capital, to maintain and increase the supply of the affected service*

[108] Australian Competition Tribunal, 2004, *Re Seven Network Limited (No 4)*, December, page 25 [121], in discussing the objective of Part XIC of the *Trade Practices Act 1974* (Cth) (**TPA**) (now the *Competition and Consumer Act 2010* (Cth) (**CCA**)), being the long term interests of end-users', on which the NEO was modelled.

[109] Australian Competition Tribunal, 2004, *Re Seven Network Limited (No 4)*, December, page 25 [120] and Attachment C6, Australian Competition Tribunal, 2009, *Application by Chime Communications Pty Ltd (No 2)*, page 15, in discussing the objective of Part XIC of the TPA (now the CCA), being the long term interests of end-users', on which the NEO was modelled.

[110] See Australian Competition Tribunal, 2004, *Re Seven Network Limited (No 4)*, December, page [121]25

[111] See Australian Competition Tribunal, 2008, *Re Application by ElectraNet Pty Limited (No 3)*, page [251]

in accordance with the value the consumers place on it. This would be contrary to the promotion of efficient investment and the long term interests of consumers.

In addition, the AER must take into account the RPPs when exercising a discretion in making those parts of a distribution determination relating to direct control network services (NEL, Section 16(2)(a)). The RPPs in Section 7A can be taken to be consistent with and to promote the objectives in Section 7. The principles are themselves stated normatively in the form of what is intended to be achieved.[112]

The RPPs are set out in Section 7A of the NEL and relevantly include:

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

(a) providing direct control network services; and

(b) complying with a regulatory obligation or requirement or making a regulatory payment.

(3) 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-

(a) efficient investment in a distribution system … with which the operator provides direct control network services; and

(b) the efficient provision of electricity network services; and

(c) the efficient use of the distribution system … with which the operator provides direct control network services.

…

(5) 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.

The Tribunal has had cause to consider the first of these principles and has stated as follows with respect to the intent and operation of that RPP:[113]

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112 See Australian Competition Tribunal, 2009, *Application by Energy Australia and Others* (with Corrigendum), page[79]

113 See Australian Competition Tribunal, 2009, *Application by Energy Australia and Others* (with Corrigendum), page[81-82]

It might be asked why the NEL principles require that the regulated NSP be provided with the opportunity to recover at least its efficient costs. Why 'at least'? The issue of opportunity is critical to the answer. The regulatory framework does not guarantee recovery of costs, efficient or otherwise. Many events and circumstances, all characterized by various uncertainties, intervene between the ex ante regulatory setting of prices and the ex post assessment of whether costs were recovered. But if, as it were, the dice are loaded against the NSP at the outset by the regulator not providing the opportunity for it to recover its efficient costs (eg, by making insufficient provision for its operating costs or its cost of capital), then the NSP will not have the incentives to achieve the efficiency objectives, the achievement of which is the purpose of the regulatory regime.

Thus, given that the regulatory setting of prices is determined prior to ascertaining the actual operating environment that will prevail during the regulatory control period, the regulatory framework may be said to err on the side of allowing at least the recovery of efficient costs. This is in the context of no adjustment generally being made after the event for changed circumstances.

3.2.2 Constituent decision on opex

The constituent decisions on which the distribution determination for ActewAGL Distribution for the subsequent regulatory control period is predicated relevantly include:[114]

- a decision on the annual revenue requirement for ActewAGL Distribution for each regulatory year of the regulatory control period to which the determination relates; and
- a decision in which the AER either accepts ActewAGL Distribution's total opex forecast for that regulatory control period or does not accept that forecast, in which case the AER must determine an estimate of ActewAGL Distribution's required opex for that period.

Clause 11.56.4(c) of the Rules provides that, for the purpose of making a distribution determination for ActewAGL Distribution for the subsequent regulatory control period, the AER must determine (amongst other things) the annual revenue requirement for ActewAGL Distribution for each regulatory year of the subsequent regulatory control period and its total revenue requirement for the subsequent regulatory control period, as if the subsequent regulatory control period comprised the transitional regulatory control period and all of the regulatory years of the subsequent regulatory control period and the transitional regulatory control period were not a separate regulatory control period. That Clause further provides, for the avoidance of doubt, that the AER must determine a notional annual revenue requirement for the regulatory year that comprises the transitional regulatory control period.

[114] *National Electricity Rules,* Clauses 6.12.1(2) and (4)

The annual revenue requirement for ActewAGL Distribution for each regulatory year of the 2014-19 regulatory control period must be determined using a building block approach, under which the building blocks relevantly include the forecast opex for that year as accepted or amended by the AER in making the distribution decision.[115]

3.2.3 The opex criteria, opex objectives and opex factors

The AER is required to accept ActewAGL Distribution's forecast opex where it is satisfied that the forecast opex for the regulatory control period reasonably reflects the following criteria (opex criteria) in Clause 6.5.6(c) of the Rules, being:

- the efficient costs of achieving the opex objectives specified in Clause 6.5.6(a) of the Rules (opex objectives);
- the costs that a prudent operator would require to achieve the opex objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

Similarly if the AER is not so satisfied and, accordingly, does not accept ActewAGL Distribution's forecast of required opex, the AER must estimate ActewAGL Distribution's required opex that it is satisfied reasonably reflects the opex criteria taking into account the matters specified in Clause 6.5.6(e) of the Rules (opex factors) (Clauses 6.5.6(d) and 6.12.1(4)(ii) of the Rules). The opex objectives in Clause 6.5.6(a) of the Rules are to:

- meet or manage the expected demand for standard control services over the regulatory control period;
- comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
- to the extent that there is no applicable regulatory obligation or requirement in relation to:

  (a) the quality, reliability or security of supply of standard control services; or

  (b) the reliability or security of the distribution system through the supply of standard control services,
- to the relevant extent:

  (a) maintain the quality, reliability and security of supply of standard control services; and

  (b) maintain the reliability and security of the distribution system through the supply of

[115] *National Electricity Rules*, Clauses 6.4.3(a)(7) and (b)(7)

standard control services; and

- maintain the safety of the distribution system through the supply of standard control services.

In deciding whether or not it is satisfied that the forecast opex for the regulatory control period reasonably reflects the opex criteria, the AER must have regard to the opex factors specified in Clause 6.5.6(e) of the Rules, including, relevantly:

- the most recent annual benchmarking report that has been published under Clause 6.27 and the benchmark operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period;
- the actual and expected operating expenditure of the DNSP during any preceding regulatory control periods;
- the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the DNSP in the course of its engagement with electricity consumers;
- the relative prices of operating and capital inputs;
- the substitution possibilities between operating and capital expenditure;
- whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the DNSP under Clauses 6.5.8 or 6.6.2 to 6.6.4;
- the extent the operating expenditure forecast is referable to arrangements with a person other than the DNSP that, in our opinion, do not reflect arm's length terms;
- whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under Clause 6.6A.1(b);
- the extent to which the DNSP has considered and made provision for efficient and prudent non-network alternatives;
- any relevant final project assessment conclusions report published under 5.17.4(o),(p) or (s); and
- any other factor we consider relevant and which we have notified the DNSP in writing, prior to the submission of its revised regulatory proposal under Clause 6.10.3, is an operating expenditure factor.

Under Clause 6.27 of the Rules, the AER must prepare and publish an annual benchmarking report the purpose of which is to describe the relative efficiency of each DNSP in providing direct control services over a 12 month period (Clause 6.27(a)).

Clause 6.27(c) provides that, subject to paragraphs (d) and (e), the AER must publish an annual benchmarking report at least every 12 months. Clause 6.27(d) and (e), in turn, provide that the first annual benchmarking report must be published by 30 September 2014 and the second annual benchmarking report by 30 November 2015.

Clause 8.7.4 (excluding Clause 8.7.4(a)) applies in respect of the preparation of an annual benchmarking report (Clause 6.27(b)). Clause 8.7.4 relevantly provides:

(b) In the course of preparing a network service provider performance report, the AER:

- (1) must consult with the network service provider or network service providers to which the report is to relate; and
- (2) must consult with the authority responsible for the administration of relevant jurisdictional electricity legislation about relevant safety and technical obligations; and
- (3) may consult with any other persons who have, in the AER's opinion, a proper interest in the subject matter of the report; and
- (4) may consult with the public.

(c) A network service provider to which the report is to relate:

- (1) must be allowed an opportunity, at least 30 business days before publication of the report, to submit information and to make submissions relevant to the subject matter of the proposed report; and
- (2) must be allowed an opportunity to comment on material of a factual nature to be included in the report.

3.2.4 The scheme of the Rules in respect of opex allowances

Significantly, the scheme of the Rules is that ActewAGL Distribution's proposal is the starting point for the AER to determine its opex allowance. This is evident from the provisions of the Rules discussed above. It is also evidenced by the AEMC's 2012 Rule Determination, wherein the AEMC relevantly stated:[116]

> *The NSP's proposal is necessarily the procedural starting point for the AER to determine a capex or opex allowance. The NSP has the most experience in how a network should be run, as well as holding all of the data on past performance of its network, and is therefore in the best position to make judgments about what expenditure will be required in the future. Indeed, the NSP's proposal will in most cases be the most significant input into the AER's decision.*

[116] See Attachment C5, AEMC, 2012, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012,* November, page 111

It is only where the AER is not satisfied that ActewAGL Distribution's forecast opex for the regulatory control period reasonably reflects the opex criteria that the Rules permit the AER to determine on its own estimate of ActewAGL Distribution's required opex. While the analysis performed by the AER may be relevant to both the assessment of whether ActewAGL Distribution's proposal is reasonable and the determination of an appropriate substitute in the event that the AER decides that proposal is not reasonable, and the AER may permissibly approach both exercises by determining its own forecast of expenditure based on the material before it, it is not permissible for the AER to set aside ActewAGL Distribution's proposal and replace it with its own. Thus, the AEMC stated in establishing the provisions of Chapter 6A of the Rules on which the provisions of Chapter 6 are based:[117]

> *In exercising its judgement the AER must also have regard to the information provided in the TNSP's proposal and the other evidentiary considerations specified in the Rule. That is, the AER is not at large in being able to reject the TNSPs forecast and replace it with its own. It must also provide reasons in terms of the decision criteria and the factors for both a rejection of the forecasts and their replacement with forecasts that it considers do meet the requirements of the Rule.*

This remains the AEMC's view following the 2012 Rule amendments. It relevantly stated, in its 2012 Rule Determination:[118]

> *The Commission remains of the view that the AER is not "at large" in being able to reject the NSP's proposal and replace it with its own. The obligation to accept a reasonable proposal, reflects the obligation that all public decision-makers have to base their decisions on sound reasoning and all relevant information required to be taken into account. … To the extent the AER places probative value on the NSP's proposal, which is likely given the NSP's knowledge of its own network, then the AER should justify its conclusions by reference to it, in the same way it should regarding any other submission of probative value.*

While express reference to 'the circumstances of the relevant [DNSP]' was removed from Clause 6.5.6(c)(2) by the 2012 amendments to the Rules, the AER must still have regard to ActewAGL Distribution's circumstances in making its decision on ActewAGL Distribution's required opex. This is a necessary consequence of the opex criteria, which require a consideration of the costs of achieving the opex objectives. The AEMC explained the position in its 2012 Rule Determination

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[117] See Attachment C6, AEMC, 2006, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, November, page 53

[118] See Attachment C5, AEMC, 2012, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012,* November, page 112

as follows:[119]

> *The Commission is of the view that the removal of the "individual circumstances" Clause does not enable the AER to disregard the circumstances of a NSP in making a decision on capex and opex allowances… Should the phrase remain it appears that the AER's interpretation of it may restrict it from utilising appropriate benchmarking approaches to inform its decision making.*
>
> *The Commission considers that the removal of the "individual circumstances" phrase will clarify the ability of the AER to undertake benchmarking. It assists the AER to determine if a NSP's proposal reflects the prudent and efficient costs of meeting the objectives. That necessarily requires a consideration of the NSP's circumstances as detailed in its regulatory proposal.*
>
> *Under the first expenditure criterion the AER is required to accept the forecast if it reasonably reflects the efficient costs of achieving the opex objectives. These include references to the costs to meet demand, comply with applicable obligations, and maintain quality, reliability and security of supply of services and of the system. These necessarily require an assessment of the individual circumstances of the business in meeting these objectives. So to the extent that different businesses have higher standards, different topographies or climates, for example, these provisions lead the AER to consider a NSP's individual circumstances in making a decision on its efficient costs.*

While the opex factors contemplate that the AER will have regard to economic benchmarking analysis, in the form of the annual benchmarking report published under Clause 6.27 of the Rules, in assessing ActewAGL Distribution's forecast of required opex, the Rules do not envisage that the AER will give primacy to such analysis. Rather, the economic benchmarking analysis in the most recent annual benchmarking report is just one of a number of opex factors and benchmarking analysis is not a substitute for the role of ActewAGL Distribution's proposal. That this is the statutory scheme established by the Rules is evidenced by the AEMC's 2012 Rule Determination, wherein the AEMC relevantly stated:[120]

> *Benchmarking is but one tool the AER can utilise to assess NSPs' proposals. It is not a substitute for the role of the NSP's proposal.*

The AER correctly observes, in its draft decision,[121] that it has a discretion with respect to the

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[119] See Attachment C5, AEMC, 2012, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012,* November, page 107

[120] See Attachment C5, AEMC, 2012, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012,* November, page 107

[121] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, pages 7-10

relative weight to be accorded to the opex factors. As the AER notes, the AEMC relevantly observed in its 2012 Rule Determination:[122]

> *As mandatory considerations, the AER has an obligation to take capex and opex factors into account, but this does not mean that every factor that will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.*

The AER's discretion is not, however, unlimited. In determining the relative weight to accord to the opex factors, the AER must exercise its discretion reasonably, in a manner that will contribute to the achievement of the NEO and having regard to the RPPs. It cannot, for example, ascribe weight to one of those factors and none to another of those factors in circumstances where this is not reasonable on the balance of the evidence before it.

The AER is required to exercise judgment in deciding whether it is satisfied that the forecasts reflect the opex criteria, having regard to the opex factors. The formulation of the statutory test for acceptance of ActewAGL Distribution's required opex by reference to whether the forecast 'reasonably reflects' the opex criteria introduces a significant leeway of choice for the AER, albeit one that is constrained by the mandatory agenda established by the opex criteria, while the requirement that the AER be 'satisfied' affords it some leeway in deciding whether to accept a forecast as reasonable.[123] Further, as the opex criteria and the opex objectives by reference to which those criteria are specified are evaluative and subjective in nature, the AER is required to exercise judgment in deciding whether the criteria are satisfied.[124] In exercising that discretion and judgment, the AER must do so in a manner that will contribute to the achievement of the NEO and having regard to the RPPs.

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[122] See Attachment C5, AEMC, 2012, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012,* November, pages 115

[123] See, for example, Attachment C7, Williams SC, N. and Higgins, R., 2006, *Memorandum of Advice In the matter of the draft National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006*, October (which was provided to the AEMC during the making of Attachment 10, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, and opines on the provisions of Chapter 6A of the Rules governing opex and capex forecasts on which Clauses 6.5.6 and 6.5.7 of the Rules were based) at [36], [44] and [74.3]

[124] As above at [64] and [74.2]

3.3 Background

3.3.1 AER's stated approach to assessing expenditure forecasts

In 2013, following the significant changes to the NER in 2012, the AER undertook a *Better Regulation* program. As part of that program, in November and December 2013, the AER published a number of Guidelines (together with Explanatory Statements) relevant to its assessment of a DNSP's expenditure proposal. Relevantly, in November 2013, as required by Clause 6.2.8(a) of the NER, the AER published the following:

- the AER's Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2013 (Expenditure Forecast Assessment Guideline); and

- the AER's Better Regulation Expenditure Forecast Assessment Guideline - Explanatory Statement, November 2013 (Expenditure Forecast Assessment Explanatory Statement).

The Expenditure Forecast Assessment Guideline specifies the approach that the AER proposes to use to assess the forecasts of opex and capex that form part of a DNSP's regulatory proposal and the information the AER requires for the purpose of that assessment.[125] The Guideline is not mandatory and does not bind the AER or the DNSPs; however, if the AER makes a distribution determination which is not in accordance with the Guideline, the AER must state its reasons for departing from the Guideline in that determination.[126]

3.3.1.1 *AER's approach to assessing opex forecasts*

In its Expenditure Forecast Assessment Guideline, the AER states that it prefers to follow a "base-step-trend" approach to assessing most opex.[127] Under this approach, the AER uses a "revealed cost" approach to assessing opex in the 'base year' (usually the penultimate regulatory year of the regulatory control period preceding that to which the distribution determination relates). It assesses whether opex in the base year is efficient and, if necessary, adjusts the DNSP's revealed costs to remove inefficient costs. The AER then accounts for any changes in efficient costs in the base year and each year of the forecast regulatory control period.

The AER states that, typically, it will adjust base year opex by applying an annual rate of change for each year of the forecast regulatory control period (which accounts for changes in real prices,

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[125] *National Electricity Rules,* clause 6.4.5(a)

[126] *National Electricity Rules,* clause 6.2.8(c)

[127] See Attachment C8, AER, 2013, *Expenditure Forecast Assessment Guideline*, November, page 22

output growth and productivity in that period).[128] In addition, step changes may be added or subtracted for any other costs not captured in base opex or the rate of change that are required for forecast opex to meet the opex criteria in the Rules.[129]

In describing its proposed general approach to assessing a DNSP's forecast expenditure, the AER states in its Expenditure Forecast Assessment Guideline:

> *We will typically compare the DNSP's total forecast with an alternative estimate that we develop from relevant information sources. To calculate this alternative estimate we will consider a range of assessment techniques. Some of our techniques will assess the DNSP's forecast at the total level; others will assess components of the DNSP's forecast. Our estimate is unlikely to exactly match the DNSP's forecast. However, by comparing it to the DNSP's forecast, we can form a view as to whether or not we consider the DNSP's forecast reasonably reflects the expenditure criteria. Therefore, if a DNSP's total capex or opex forecast is greater than the estimates we develop using our assessment techniques, and there is no satisfactory explanation for this difference, we will form the view that the DNSP's estimate does not reasonably reflect the expenditure criteria. In this case, we will substitute our own estimate that does reasonably reflect the expenditure criteria. If our estimate demonstrates that the DNSP's forecast reasonably reflects the expenditure criteria, we will accept the forecast. Whether we accept a DNSP's forecast or do not accept it, we will provide the reasons for our decision. When we develop alternative estimates as a means of assessing a DNSP's proposal, we will generally develop an efficient starting point or underlying efficient level of expenditure. We then adjust this for changes in demand forecasts, input costs and other efficient increases or decreases in expenditure, allowing us to construct a total forecast that we are satisfied reasonably reflects the expenditure criteria. For recurrent expenditure, we prefer to use revealed (past actual) costs as the starting point for assessing and determining efficient forecasts. If a DNSP operated under an effective incentive framework, actual past expenditure should be a good indicator of the efficient expenditure the NSP requires in the future. The ex-ante incentive regime provides an incentive to improve efficiency (that is, by spending less than the AER's allowance) because DNSPs can retain a portion of cost savings made during the regulatory control period. However, the incentive to spend less than our allowance must not be to the detriment of the quality of the services the DNSP supplies.*

[128] See Attachment C8, AER, 2013, *Expenditure Forecast Assessment Guideline*, November, page 23 and Attachment C9, AER 2013, *AER Explanatory Statement: Expenditure Forecast Assessment Guideline*, November, page 61

[129] See Attachment C8, AER, 2013, *Expenditure Forecast Assessment Guideline*, November, page 23 and Attachment C9, AER, 2013, *AER Explanatory Statement: Expenditure Forecast Assessment Guideline*, page 61

> *Consequently we apply various incentive schemes (such as the efficiency benefit sharing scheme (EBSS), the service target performance incentive scheme (STPIS) and the capital expenditure sharing scheme (CESS)) to provide DNSPs with a continuous incentive to improve their efficiency in supplying electricity services to the standard demanded by consumers.*
>
> *While we examine revealed costs in the first instance, we must test whether DNSPs have responded to the incentive framework in place. That is, we must determine whether or not the DNSP's revealed costs are efficient. For example, whether the DNSP's past performance was efficient relative to its peers and whether the DNSP has improved its efficiency over time. For this reason, we will assess the efficiency of base year expenditures using our techniques, beginning with economic benchmarking and category analysis, to determine if it is appropriate for us to rely on a DNSP's revealed costs.*
>
> *...*
>
> *Our approach for both opex and capex will place greater reliance on benchmarking techniques than we have in the past. We will, for example, use benchmarking to assist us in determining the appropriateness of revealed costs. We will also benchmark DNSPs across standardised expenditure categories to compare relative efficiency.* [130]

In describing its approach to assessing opex in its Expenditure Forecast Assessment Guideline, the AER states:

> *We prefer a 'base-step-trend' approach to assessing most opex criteria. However, when appropriate, we may assess some opex categories using other forecasting techniques, such as an efficient benchmark amount. We will assess opex categories forecast using other forecasting techniques on a case-by-case using the assessment techniques outlined in Section 2.4. We will also assess whether using alternative forecasting techniques in combination with a 'base-step-trend' approach produces a total opex forecast consistent with the opex criteria.* [131]

The AER discusses its approach to assessing opex in Section 5 of its Expenditure Forecast Assessment Explanatory Statement. The AER states:

> *Consistent with past practice, we prefer using a revealed cost approach to assess most opex cost categories (which assumes opex is largely recurrent). Specifically we intend to use the 'base-step-trend' approach. If a NSP has operated under an effective incentive framework, and sought to*

[130] See Attachment C8, AER, 2013, *Expenditure Forecast Assessment Guideline*, November, pages 7-8 and Attachment C9, AER, 2013, *AER Explanatory Statement: Expenditure Forecast Assessment Guideline*, November, page 42

[131] See Attachment C8, AER, 2013, *Expenditure Forecast Assessment Guideline*, November, page 22

maximise its profits, the actual opex incurred in a base year should be a good indicator of the efficient opex required. However, we must test this, and if we determine that a NSP's revealed costs are not efficient, we will adjust them to remove inefficient costs. Details of our base year assessment approach are below. Once we have assessed the efficient opex in the base year we then account for any changes in efficient costs in the base year and each year of the forecast regulatory control period. There are several reasons why efficient opex in a regulatory control period could differ from the base year. Typically, we will adjust base year opex for:

- *output growth*
- *real price growth*
- *productivity growth.*

An annual 'rate of change' will incorporate these factors. Any other costs base opex and the rate of change do not compensate can be added as a step change. When assessing step changes particular consideration must be given to whether the costs are already compensated for elsewhere in the opex forecast. [132]

The AER states in its Expenditure Forecast Assessment Explanatory Statement that it may adjust base opex to remove inefficient costs for two reasons, being:

- *a DNSP's recurrent expenditure is inefficient compared to its peers; and/or*
- *a DNSP's base year expenditure is not reflective of efficient recurrent expenditure due to a one-off factor in the base year.* [133]

In deciding whether a DNSP's expenditure is inefficient, the AER states it will consider:

- *the results of its expenditure review techniques, including economic benchmarking, category analysis and detailed engineering review; and*
- *the DNSP's regulatory proposal and stakeholder submissions.* [134]

The AER states in its Expenditure Forecast Assessment Guideline that it will assess opex for the

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[132] See Attachment C9, AER, 2013, *AER Explanatory Statement: Expenditure Forecast Assessment Guideline*, November, page 61

[133] See Attachment C9, AER, 2013, *AER Explanatory Statement: Expenditure Forecast Assessment Guideline*, November, page 93

[134] See Attachment C9, AER, 2013, *AER Explanatory Statement: Expenditure Forecast Assessment Guideline*, November, page 93

forecast regulatory control period by applying an annual rate of change for each year of the forecast regulatory control period where the annual rate of change for year t is:

$$\text{Rate of change}_t = \text{output growth}_t + \text{real price growth}_t - \text{productivity growth}_t$$ [135]

In respect of determining the efficient opex in the base year using various assessment techniques and the relationship with the productivity growth element of the rate of change, the AER states in the Expenditure Forecast Assessment Explanatory Statement:

> *We need to be able to decompose our productivity change measure into the sources of productivity change to separately apply the base year adjustment and productivity forecast. We propose to do this by:*
>
> *having regard to the partial factor productivity (PFP) differential in the base year together with information from category analysis benchmarking to gauge the scope of inefficiency to be removed by the base year adjustment*
>
> *using the PFP change of the most efficient business (or highly efficient businesses as a group) to gauge the scope of further productivity that may be achieved by individual businesses—this assumes that relevant drivers (such as technical change and scale change) and their impact remain the same over the two periods considered (historical versus forecast).*
>
> *For some NSPs, future productivity gains may be substantially different from what they achieved in the past. For example, inefficient NSPs may significantly improve productivity*
>
> *and become highly efficient at the end of the sample period. This would reduce the potential for them to make further productivity gains in the following period. Similar issues apply to the productivity change achieved by the industry as a whole. If the group includes both efficient and inefficient NSPs, the industry-average productivity change may be higher than what an individual NSP can achieve. To the extent inefficient NSPs are catching up to the frontier, the industry average productivity change will include both the average moving closer to the frontier and the movement of the frontier itself. By decomposing productivity change into catching up to the frontier and frontier shift we can account for these.* [136]

3.3.1.2 *AER's benchmarking assessment techniques*

The assessment techniques the AER states that it will use for assessing opex and capex include

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[135] See Attachment C8, AER, 2013, *Expenditure Forecast Assessment Guideline*, November, page 23

[136] See Attachment C8, AER, 2013, *Expenditure Forecast Assessment Guideline*, November, section 2.4.1

economic benchmarking, category benchmarking and aggregated category benchmarking.[137] In respect of economic benchmarking, the Expenditure Forecast Assessment Guideline states:[138]

> *Economic benchmarking applies economic theory to measure the efficiency of a DNSP's use of inputs to produce outputs, having regard to operating environment factors. It will enable us to compare the performance of a DNSP with its own past performance and the performance of other DNSPs. We will apply a range of economic benchmarking techniques, including (but not necessarily limited to):*
>
> - *multilateral total factor productivity*
> - *data envelopment analysis*
> - *econometric modelling.*

In respect of category level benchmarking, the Expenditure Forecast Assessment Guideline states:

> *We will benchmark across DNSPs by expenditure categories on a number of levels including:*
>
> - *total capex and total opex*
> - *high level categories (drivers) of expenditure (for example customer driven capex or maintenance opex)*
> - *subcategories of expenditure.*
>
> *We may benchmark further at the following low levels:*
>
> - *unit costs associated with given works (for example, the direct labour and material cost required to replace a pole)*
> - *unit volumes associated with given works (for example, kilometres of conductor replaced per year).* [139]

In respect of aggregated category benchmarking, the Expenditure Forecast Assessment Guideline states:

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[137] See Attachment C8, AER, 2013, *Expenditure Forecast Assessment Guideline*, November, section 2.4.1

[138] See Attachment C8, AER, 2013, *Expenditure Forecast Assessment Guideline*, November, page 13

[139] See Attachment C8, AER, 2013, *Expenditure Forecast Assessment Guideline*, November, page 13

> *In addition to detailed category benchmarks we are likely to use aggregated category benchmarks, which capture information such as how much a DNSP spends per kilometre of line length or the amount of energy it delivers. We intend to improve these benchmarks by capturing the effects of scale and density on DNSP expenditures.*[140]

In its Expenditure Forecast Assessment Explanatory Statement, the AER states in respect of economic benchmarking and category analysis techniques:[141]

> *We consider the new assessment techniques will assist the AER's assessment of whether NSPs proposed expenditure is at efficient levels in the following ways:*
>
> - *Economic benchmarking techniques assist in assessing the efficiency of NSPs relative to their performance across time and against other NSPs. These techniques develop an efficient production frontier. From this, we can measure a NSP's relative productive performance in terms of its distance from that frontier. The techniques can control for the effects of scale, input mix, and operating environment factors for in measuring technical efficiency (that is, distance from the frontier).*
> - *Category or driver-based analysis will assist in determining an efficient level of expenditure in a particular category of expenditure. The techniques included in this analysis include benchmarking, modelling and engineering reviews. We can use this analysis to contrast and compare factors influencing expenditure across NSPs.*

In addition, in respect of economic benchmarking, the Expenditure Forecast Assessment Explanatory Statement states:

> *Economic benchmarking applies economic theory to measure the efficiency of a NSP's use of inputs to produce outputs, having regard to environmental factors. It will enable us to compare the performance of a NSP with its own past performance or the performance of other NSPs.*
>
> *We propose to take a holistic approach to using economic benchmarking techniques, but intend to apply them consistently. We will determine which techniques to apply at the time of determinations, rather than specify economic benchmarking techniques in our Guideline. This will allow us to refine our techniques over time.*
>
> *In determinations, we will use economic benchmarking models based on their intended use, and the availability and quality of data. Some models could be used to cross-check the results of other*

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[140] See Attachment C8, AER, 2013, *Expenditure Forecast Assessment Guideline*, November, page 13

[141] See Attachment C9, AER, 2013, *AER Explanatory Statement: Expenditure Forecast Assessment Guideline*, November, page 13

techniques. At this stage, it is likely we will apply multilateral total factor productivity (MTFP), data envelopment analysis (DEA) and an econometric technique to forecast opex. We anticipate including economic benchmarking in annual benchmarking reports.

We are likely to use economic benchmarking to (among other things):

1. *measure the rate of change in, and overall efficiency of, NSPs. This will provide an indication of the efficiency of historical expenditures and the appropriateness of their use in forecasts.*
2. *develop a top down total cost forecast of total expenditure.*
3. *develop a top down forecast of opex taking into account:*
4. *the efficiency of historical opex*

the expected rate of change for opex.[142]

The AER expands on its approach to economic benchmarking in Attachment A to the Expenditure Forecast Assessment Guideline and outlines its economic benchmarking data requirements in Attachment B to the Expenditure Forecast Assessment Guideline.

3.3.2 AER's annual benchmarking report

In purported compliance with its obligation under Clause 6.27 of the Rules to publish an annual benchmarking report, the AER published its first annual benchmarking report for distribution, *Electricity distribution network service providers Annual benchmarking report*, on 27 November 2014 (Annual Benchmarking Report).

To this end, consistent with its stated approach in its Expenditure Forecast Assessment Guideline and Expenditure Forecast Assessment Explanatory Statement, for the purposes of assessing a DNSP's expenditure forecasts (including opex forecasts) for their forthcoming regulatory control periods, the AER sought benchmarking analysis information from DNSPs. Specifically, the AER issued final regulatory information notices for economic benchmarking requirements on 28 November 2013. ActewAGL Distribution provided information to the AER in response to its benchmarking regulatory information notice.

The AER then released a *Draft Electricity distribution network service providers Annual benchmarking report* (Draft Annual Benchmarking Report) to ActewAGL Distribution and other DNSPs on a confidential basis for comment in August 2014.

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[142] See Attachment C9, AER, 2013, *AER Explanatory Statement: Expenditure Forecast Assessment Guideline*, November, pages 78-79 and AER, 2014, *ActewAGL Network Information - RIN responses,* accessed on 17 January 2015, < http://www.aer.gov.au/node/24311>

The AER's subsequent publication of its Annual Benchmarking Report post-dated the stipulated statutory date of 30 September by close to two months and, thus, coincided with publication of the draft decision. At the same time, the AER published its draft decision and the accompanying Economic Insights report, titled *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs* and dated 17 November 2014 (Economic Insights Report), which contains substantial additional economic benchmarking analysis not reflected in the Draft Annual Benchmarking Report on which the AER consulted and on which the AER relies in the draft decision.

While the AER provided ActewAGL Distribution with a copy of the Annual Benchmarking Report and the Economic Insights Report prior to their publication, under cover of a letter from Ms Paula Conboy, Chair of the AER, dated 18 November 2014, their provision to ActewAGL Distribution nonetheless post-dated the stipulated statutory date for publication of the Annual Benchmarking Report by in excess of 6 weeks and pre-dated publication of the draft decision by only 9 days.

Further, it is unclear whether and the extent to which the AER discharged its obligation under Clause 8.7.4(b)(2) of the Rules to consult with 'the authority responsible for the administration of relevant *jurisdictional electricity legislation*' in respect of the ACT (ACT's Technical and Safety Regulator) about relevant safety and technical obligations in preparing the Annual Benchmarking Report.

3.4 Base year opex

3.4.1 Overview

The AER concluded that the main difference between its opex forecast and ActewAGL Distribution's forecast was the portion of opex in the base year that was efficient.[143] The AER's detailed analysis of ActewAGL Distribution's base year opex is contained in Appendix A to Attachment 7 to the draft decision.

In this Section 3.4, ActewAGL Distribution briefly outlines its base year opex proposal (in Section 3.4.2) and the AER's draft decision on base year opex (in Section 3.4.3) and then details ActewAGL Distribution's response to that draft decision (in Section 3.4.4) and sets out its revised proposal (in Section 3.4.5).

[143] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Overview*, November, page 51

In ActewAGL Distribution's response to the AER's draft decision on base year opex (in Section 3.4.4), it contends as follows:

- In preparing the benchmarking analysis relied on by the AER in making that draft decision, the AER has not complied with the procedural requirements of the Rules and has denied ActewAGL Distribution procedural fairness. This is discussed further in Section 3.4.4.1;
- The AER's draft decision on base year opex is not in accordance with law, involves a material error, or material errors, of fact and/or an incorrect exercise of discretion, and/or is unreasonable for the reasons discussed in Sections 3.4.4.2 to 3.4.4.11 below; and
- The AER's draft decision on base year opex does not contribute to the achievement of the NEO and, thus, does not result in a draft decision on opex or an overall draft decision that contributes to the achievement of the NEO to the greatest degree as required by Section 16(2)(d) of the NEL. This is discussed further in Section 3.4.4.12.

3.4.2 ActewAGL Distribution's proposal

ActewAGL Distribution used a combination of zero-based and base year approaches in forecasting its total opex for the 2014-19 period included in its building block proposal. The 2012/13 base year amount (incorporating adjustments and excluding network maintenance) was $43.5 million. Prior to excluding network maintenance the amount was $67.8 million.[144] The AER in its draft decision calculated its own proposed base year opex of $66.8 million.[145]

3.4.3 AER draft decision

In assessing base year opex, the AER has regard to two opex factors in addition to the opex factors specified in Clause 6.5.6(e)(4) to (10) of the Rules. Those factors are:

- *the AER's benchmarking data sets including, but not limited to:*
    - *(a) data contained in any economic benchmarking RIN, category analysis RIN, reset RIN or annual reporting RIN;*

[144] ActewAGL, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period*, *Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), page 224

[145] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-19, Table 7.4

(b) any relevant data from international sources; and

(c) data sets that support econometric modelling and other assessment techniques consistent with the approach in the AER's Expenditure Forecast Assessment Guideline,

as updated from time to time; and

- *economic benchmarking techniques for assessing benchmark efficient expenditure including stochastic frontier analysis and regressions utilising functional forms such as Cobb Douglas and Translog.* [146]

The AER concludes that its calculation of ActewAGL Distribution's base opex in the 2012/13 base year of $66.8 million ($2013/14) is materially inefficient.[147] Accordingly, it adopts a substitute base year opex for 2012/13 of $42.2 million, 36.8 per cent lower than the AER's calculation of base year opex, for the purpose of forecasting opex for the 2014/19 period.[148] In doing so the AER abandoned the use of the Efficiency Benefit Sharing Scheme (EBSS) and revealed cost approach in informing efficient base year opex.

The AER engaged Economic Insights to assist with the application of economic benchmarking and advise on:

- *whether the AER should make adjustments to base opex for the NSW and ACT DNSPs based on the results from economic benchmarking models; and*
- *the productivity change to be applied to forecast opex for the NSW and ACT DNSPs.* [149]

In its report, Economic Insights use a range of economic benchmarking methods to assess the

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[146] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, pages 7-11 and 7-24

[147] ActewAGL Distribution notes the AER's use of an 18 month lagged CPI in calculating this figure. The AER has not explained its logic for this approach for the purposes of cost escalation and ActewAGL Distribution contends that the most recent available estimates of CPI should be used to provide the most accurate real opex estimate.

[148] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-19

[149] Economic Insights, 2014, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November, page iv. While the draft decision refers to an Economic Insights Report of October 2014 (see for example, footnote 35 of Appendix 7), the 17 November 2014 report is the report provided on the AER's website in connection with the draft decision.

relative opex cost efficiency of Australian DNSPs, including a Cobb Douglas stochastic frontier analysis opex cost function model (CD SFA), Cobb Douglas and Translog least squares econometrics (LSE) opex cost function models and multilateral total factor productivity (MTFP) and multilateral partial factor productivity (MPFP) indexes.[150]

On the basis of the raw benchmarked efficiency scores developed by Economic Insights using these five assessment techniques (set out in Table A.2), the AER found that ActewAGL Distribution is on average about 40 per cent as efficient as the most efficient service providers in the NEM (CitiPower and Powercor) on the five different measures.[151] The AER cited with approval Economic Insights' conclusion that the similar results from the application of the differing methods to differing datasets engenders confidence in the results[152] and concludes that the economic benchmarking results reinforce each other.[153]

On the advice of Economic Insights, the AER used results from its preferred CD SFA benchmarking model as a starting point for determining an alternative estimate of ActewAGL Distribution's base year opex.[154] The CD SFA model relies upon four variables to determine a raw efficiency score:

- Customer numbers;
- Circuit length;
- Ratched maximum demand; and

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[150] Economic Insights, 2014, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs Report*, November, page iv and AER, 2014, *Draft decision ActewAGL Distribution determination 2015-16 to 2018-19 Overview*, November, pages 7-52 to 7-61.

[151] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Overview*, November, page 52 and AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, pages 7-26 and 7-27

[152] AER, 2014, *AER Draft decision ActewAGL distribution determination: Overview*, November, page 52 and AER, 2014*, Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-28, referring to Economic Insights, 2014, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November, pages 46 to 47.

[153] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-33

[154] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, pages 7-19 and 7-27

- Proportion of underground cabling.

While application of ActewAGL Distribution's raw efficiency score compared to the frontier using this model would dictate a reduction to ActewAGL Distribution's base opex of 61 per cent, the AER determined on making three adjustments to the "raw" benchmarking results (which imply a base opex of $26.0m), on the recommendation of Economic Insights, as follows:

- Rather than using the NEM frontier service provider, CitiPower, as the benchmark for efficiency comparisons, the first adjustment is to set a lower benchmark based on the weighted average of the efficiency scores of the most efficient service providers in the NEM, specifically those service providers with efficiency scores of 0.75 or above (i.e. CitiPower, Powercor, United Energy, SA Power Networks and AusNet). This reduces the benchmark efficiency target by 9 percentage points to 0.86 from 0.95 and increases substitute base opex by +$2.7 million.[155] In recommending the making of this adjustment, Economic Insights states that it 'allows for limitations of the models with respect to the specification of outputs and inputs, data imperfections and other uncertainties'[156] in recognition that 'all models are by definition a simplification of reality and may not capture all relevant effects'.[157]
- The second adjustment is to modify the benchmark efficiency target to account for operating environment factors specific to the ACT.[158] The AER concedes that Economic Insights' benchmarking models do not account for all differences in the operating environments of DNSPs.[159] The AER is satisfied that an adjustment should be made for five significant operating environment factors affecting ActewAGL Distribution's relative performance, specifically capitalisation policy, standard control services connections, backyard reticulation, taxes and levies, and occupational health and safety regulations, and concludes that the combined impact of these adjustments on ActewAGL

[155] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure,* November, pages 7-27 to 7-28

[156] Economic Insights, 2014, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November, pages v and 47

[157] Economic Insights, 2014, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November, page 47

[158] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure,* November, page 7-27

[159] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure,* November, pages 7-32 to 7-33

Distribution is a 27.7 per cent margin on input use relative to the comparison service providers.[160] The AER also concedes that there are several other factors that could, at least collectively, impact materially on ActewAGL Distribution's relative performance, such as topography and planning regulations.[161] The AER accepts that the impact of other factors of this kind is difficult to quantify and determines on allowing for this through the addition of a 30 per cent (rather than 27.7 per cent) operating environment adjustment,[162] which effectively reduces the benchmark efficiency target by 20 percentage points to 0.66 and increases substitute base opex by +$8.6 million.[163]

- The third adjustment is made because the Cobb Douglas Stochastic Frontier Analysis model efficiency score represents ActewAGL Distribution's average efficiency for the 2006 to 2013 benchmarking period and involves the application of a trend to move the substitute base opex from a forecast of the average amount for the 2006 to 2013 period to a forecast for 2012/13, which increases substitute base opex by +$4.9 million.[164]

This results in the AER's substitute base year opex of $42.2 million that is illustrated as a waterfall chart in Figure 3.2.

[160] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure,* November, page 7-33

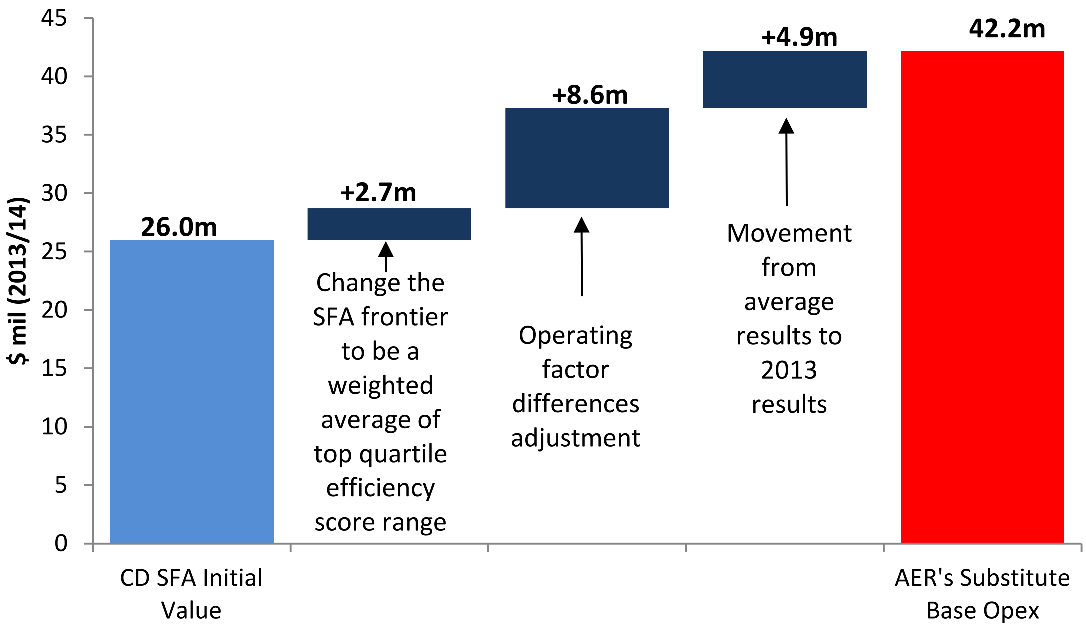
[161] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure,* November, page 7-33

[162] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure,* November, page 7-33

[163] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure,* November, pages 7-27 to 7-28

[164] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure,* November, pages 7-27 and 7-28

Figure 3.2 AER's process in making adjustments to the substitute base opex for ActewAGL Distribution



The AER states that it considered that other simpler benchmarking techniques, such as partial performance indicators, corroborate those results.[165]

The AER also states it used category analysis and detailed reviews of expenditure categories to investigate potential sources of inefficiency or high costs that might explain the gap in performance between ActewAGL Distribution and its peers.

On the basis of its category analysis, the AER's finds that:

> *Broadly, however, our analysis suggests that on the majority of the category analysis measures ActewAGL appears to have high costs relative to most other service providers. ... ActewAGL's expenditure is recorded as 'high' when its costs appear above its peers and 'comparable' where the gap is less distinct. 'Very high' indicates a substantial gap*

[165] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Overview*, November, page 52 and AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, pages 7-29 to 7-30 and 7-61 to 7-64

between other service providers. We consider these results are consistent with and support the findings of our economic benchmarking techniques. [166]

The AER develops the following table to summarise these outcomes: [167]

	ActewAGL
Labour	Very High
Total overheads	High
Total corporate overheads	Comparable
Total network overheads	Comparable
Maintenance	Very High
Emergency response	Comparable
Vegetation management	Very High

It concludes that the existence of systemic issues within ActewAGL Distribution is the likely reason why it has high expenditure on category analysis for most significant expenditure categories.[168]

The AER further concludes that its detailed review of ActewAGL Distribution's labour and vegetation management categories of expenditure tended to support this view as well.[169]

[166] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-31

[167] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-31, Table A.4

[168] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-31

[169] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-31

As a consequence of its detailed review of ActewAGL Distribution's labour and workforce practices, including a comparison of its practices with those of other service providers where relevant, the AER concludes that ActewAGL Distribution's practices are inefficient in the following respects:[170]

- ActewAGL Distribution has significantly lower proportions of outsourcing than its more efficient peers;
- workplace structure, culture and performance issues have been identified in respect of ActewAGL Distribution by its own consultant;
- large increases in the number and cost of permanent employees occurred during and in the lead up to the 2009-14 regulatory control period;
- restructuring has led to an outlay of costs with little evidence of corresponding quantifiable benefit; and
- ActewAGL Distribution's enterprise bargaining agreement contains, in some instances, more restrictive provisions on labour engagement and management than those of its peers.

The AER further concludes that the increase in ActewAGL Distribution's vegetation management expenditure, from $2.6 million ($2013/14) in 2008/09 to $5.4 million ($2013/14) in 2012/13 reflects the following inefficiencies:[171]

- the engagement of contractors primarily on an hourly rate basis rather than a work volume basis, with no foreshadowed change to this practice; and
- a lack of prudent operational risk management, resulting in a largely reactive approach to maintaining vegetation.

The AER concluded that it was satisfied that the result of its detailed review supports the overall benchmarking results.[172]

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[170] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Overview*, November, page 52 and AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure ,* November, pages 7-32 and 7-77 to 7-89

[171] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Overview*, November, page 52 and AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure ,* November, pages 7-33 and 7-77 to 7-89

[172] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-68

3.4.4 ActewAGL Distribution's response

The AER has relied heavily upon the use of its econometric benchmarking model in reaching its conclusion that ActewAGL Distribution's proposed opex does not reasonably reflect the opex criteria. The AER has then used the outcomes of the econometric model to mechanistically calculate a substitute estimate of efficient opex in the base year.

ActewAGL Distribution contends as follows in response to the AER's draft decision on base year opex:

- In preparing the benchmarking analysis relied on in the making of that draft decision, the AER has not complied with the procedural requirements of the Rules and has denied ActewAGL Distribution procedural fairness. This is discussed further in Section 3.4.4.1 below;
- The AER's draft decision on base year opex is not in accordance with law, the AER has made an error of fact or errors of fact in its findings of fact material to the making of that decision, in making that decision the AER has incorrectly exercised its discretion in all the circumstances and/or the AER's decision was unreasonable in all the circumstances; and
- The AER's draft decision on base year opex does not contribute to the achievement of the NEO and, thus, does not result in a draft decision on opex or an overall draft decision that contributes to the achievement of the NEO to the greatest degree. This is discussed further in Section 3.4.4.12 below.

ActewAGL Distribution contends that the AER's draft decision on base year opex is not in accordance with law, involves a material error, or material errors, of fact and/or an incorrect exercise of discretion, and/or is unreasonable for the following reasons:

- In making that decision, the AER has acted contrary to the statutory scheme established by the Rules in that, whereas the statutory scheme contemplates that the AER will use ActewAGL Distribution's proposal as the starting point, assess it and, if necessary, make adjustments to that proposal, and will use benchmarking as 'but one tool the AER can utilise to assess NSPs' proposals',[173] the AER has, with only limited exceptions, put aside ActewAGL Distribution's proposed base year opex and instead given primacy to benchmarking analysis in making its decision on base year opex, relying on that analysis almost exclusively to assess ActewAGL Distribution's base opex and deterministically

[173] See Attachment C5, AEMC, 2012, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012,* November, page 107

applying it to derive a substitute base opex estimate. This is discussed further in Section 3.4.4.2 below.

- The AER's mechanistic use of benchmarking is otherwise incorrect or unreasonable. The benchmarking model used by the AER suffers from flaws and does not provide robust results. As a consequence, it is not suitable for use in calculating 'efficient expenditure' in the way that the AER attempts to do in its draft decision. Given its current state of development, the appropriate role of the AER's benchmarking model is as a tool for identifying significant areas of expenditure anomaly between businesses which can then be subject to detailed investigation. The AER has instead used benchmarking mechanistically and in a manner inconsistent with international precedent. This is discussed further in Section 3.4.4.3.
- The use of benchmarking and retrospective abandonment of the EBSS undermines the incentives of the regulatory regime and creates a framework within which perverse incentives exist. The abandonment of the use of the revealed costs approach represents a significant divergence from the regulatory regime in operation during the 2009-14 period and increases the regulatory risk to ActewAGL Distribution and the industry more broadly. This is discussed further in Section 3.4.4.4.
- The AER's economic benchmarking analysis does not produce a reliable estimate of ActewAGL Distribution's efficient base opex due to numerous technical flaws in the econometric model adopted by the AER. In particular:
    - the Australian data set is immature and inconsistent and cannot be relied upon;
    - the international data is not comparable with the Australian data and limits the analysis that can be undertaken
    - the model selection has not been justified;
    - important environmental variables have been omitted from the econometric model and the AER's after modelling adjustments are arbitrary and unsubstantiated;
    - the AER's frontier adjustment from the midpoint of 2009 to 2013 has been calculated incorrectly; and
    - the efficiency frontier has been applied incorrectly.

  These matters are discussed further in Section 3.4.4.5.
- The alternative models developed by Professor Newbery are superior to those developed by Economic Insights as they undertake greater normalisation of the data and more accurately take into account ActewAGL Distribution's operating environment. The results from these alternative models indicate that there is a much tighter range of

efficiency scores. The impact on ActewAGL Distribution’s base year opex allowance range from lower opex reductions, and for some models, higher implied base year opex. These outcomes:

    - highlight the inconsistency in results generated by different benchmarking models and identify the risk of placing reliance on a single model as done by the AER; and
    - affirm that the only correct and reasonable use of benchmarking is as an informative tool to identify areas for further investigation, and that it is incorrect and unreasonable to accord the weight to benchmarking that the AER accords it in its draft decision.

  This is discussed further in Section 3.4.4.6.

- The AER's supporting PPI analysis fails to corroborate the benchmarking outcomes. Rather, the PPI analysis is a repetition of many of the technical flaws of the econometric modelling and fails to recognise limitations identified previously by the AER with respect to data quality, the one-dimensional nature of PPI analysis and the assumed linear relationship between inputs and outputs. These failings are discussed further in Section 3.4.4.7.
- The AER's supporting category analysis, as with the PPI analysis, is flawed. The simplistic analysis of opex categories in isolation, without further detailed investigation, is incapable of corroborating the benchmarking analysis. This is discussed further in Section 3.4.4.8.
- The AER considers it has undertaken a detailed review of ActewAGL Distribution’s labour costs. However, a more thorough investigation demonstrates that the AER’s analysis does not support its claims of inefficient labour levels, costs, outsourcing practices, redundancy provisions and organisational arrangements. This is discussed further in Section 3.4.4.9.
- The AER's detailed review of vegetation management assesses base year opex of its own construction rather than the total opex proposed by ActewAGL Distribution. Nevertheless, the AER’s conclusions are based on incorrect and unsupported claims regarding contracting arrangements. The AER also concludes performance has deteriorated when actual performance has improved. The AER’s flawed analysis is discussed further in Section 3.4.4.10.
- The AER's direct comparison to Jemena suffers from the same analytical flaws as the AER’s benchmarking, PPI and category analysis. The direct comparison with Jemena provides no new forms of analysis or insight and therefore produces the same unreliable results. The AER’s direct comparison analysis is discussed in Section 3.4.4.11.

The AER has not applied a variety of analytical approaches which independently substantiate its claim of ActewAGL Distribution’s inefficiency. Rather, each of the analytical techniques are variations on a common theme and are based on the same non-comparable data. As such, the AER’s conclusions do not reinforce one another but are merely a repetition of the same errors.

The flawed and unreasonable approach adopted by the AER in its draft decision has led to proposed cuts in ActewAGL Distribution’s opex of an unprecedented magnitude. The AER comments in its draft decision that the percentage reduction ‘may seem large’.[174] Clearly, the reductions do not only ‘seem large’, but are large. Such a substantial reduction in opex below current levels raises substantial concerns about whether they are realistic and achievable, and whether ActewAGL Distribution will be able to recover its efficient cost of providing safe and reliable distribution services.

3.4.4.1 *The AER’s benchmarking analysis procedures are not in accordance with law*

The AER has not complied with the procedural requirements of the Rules and has denied ActewAGL Distribution an opportunity to provide comment on the AER’s benchmarking techniques in advance of publication of the draft decision.

The scheme of the Rules is that the economic benchmarking techniques the AER will employ, and the primary economic benchmarking analysis to which it will have regard, in making a distribution determination will be disclosed in the most recently published annual benchmarking report. This is reflected in the requirement under Clause 6.5.6(e)(4) of the Rules for the AER to have regard to, amongst other opex factors, the most recent annual benchmarking report that has been published under Clause 6.27 and the benchmark opex that would be incurred by an efficient DNSP over the relevant regulatory control period.

The Rules further contemplate, against the background of the short period provided by the Rules for submission of a revised regulatory proposal, that:

- consultation on the AER's economic benchmarking techniques to be employed, and analysis to which it will have regard, in making a distribution determination will, thus, occur in the course of the consultation on the relevant annual benchmarking report required by Clause 8.7.4(b)(1) and (c) of the Rules; and
- the first such annual benchmarking report for distribution would be published by 30 September 2014 and, thus, a reasonable period in advance of the first of the AER's draft

[174] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Overview*, November, page 52 and AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure,* November, page 7-26

distribution determinations to be made in accordance with the Rules as amended by the AEMC in 2012.

However, the AER's Annual Benchmarking Report neither disclosed the economic benchmarking techniques or analysis on which the AER relies in its draft decision nor was that Report published in accordance with the timeline stipulated by Clause 6.27(d) of the Rules, with the consequence that ActewAGL Distribution has been denied the opportunity to be heard on the development of those techniques and that analysis in advance of publication of the draft decision that the Rules intend is to be afforded in consultation on the Annual Benchmarking Report.

The benchmarking techniques and analysis on which the AER relies in its draft decision but which were not included in the Draft Annual Benchmarking Report provided to ActewAGL Distribution for comment on 5 August 2014 (or the category analysis metrics and supporting data and analysis provided for comment on 15 August 2014) and, thus, on the development of which ActewAGL Distribution was not consulted in advance of the draft decision include:

- in addition to the multilateral total factor productivity ('MTFP'), partial factor productivity and category analysis included in the Draft Annual Benchmarking Report (and the category analysis metrics), analysis involving the application of two further benchmarking techniques, specifically stochastic frontier analysis (which is the AER's preferred technique) and least squared estimation regression analysis, in three further models; and
- adjustments to its benchmarking analysis to address deficiencies in that analysis in accounting for ActewAGL Distribution's operating environment.

The process adopted by the AER in developing and applying its benchmarking analysis relied upon in its opex draft decision therefore denied ActewAGL Distribution the opportunity to be heard on those matters in advance of the AER's draft decision that was contemplated by the Rules.

While the AER sought to ameliorate this injustice by providing ActewAGL Distribution with a copy of its Annual Benchmarking Report, and the Economic Insights Report detailing the primary benchmarking techniques and analysis on which the AER relies in the draft decision, in advance of the publication of that decision under cover of a letter from Ms Paula Conboy, Chair of the AER, dated 18 November 2014, this allowed ActewAGL Distribution only 9 additional calendar days to review and assess those techniques and that analysis rather than the period of 2 months contemplated by the Rules. Moreover, ActewAGL Distribution was unable to provide comment to the AER on the further benchmarking techniques and adjustments upon which it relies in its draft decision.

This is particularly concerning given that the terms of reference for the Economic Insights Report[175] suggests that the AER had ample opportunity to communicate to NSW and ACT DNSPs that a separate benchmarking analysis was being prepared for the purposes of their distribution determination processes and consult on a draft of that Report.

ActewAGL Distribution considers that, where the AER chose to rely on another benchmarking report or other benchmarking analysis, the scheme of the Rules required the AER to provide ActewAGL Distribution with an opportunity to submit information, make submissions and comment on that additional material in advance of publication of the draft decision, if that material were to be relied on in that decision.

In addition, it is unclear whether the AER discharged its obligation under Clause 8.7.4(b)(2) of the Rules to consult with the ACT's Technical and Safety Regulator about relevant technical and safety obligations in preparing its Annual Benchmarking Report.

In correspondence with the AER dated 17 November 2014, ActewAGL Distribution:

- noted the essential nature of such consultation in circumstances where the AER intends to rely on economic benchmarking analysis to disallow around 42 per cent of ActewAGL Distribution's forecast opex, so compromising its ability to ensure the continued maintenance of the quality, reliability, security and safety of its distribution system and services; and
- requested that the AER confirm either that it had consulted with the ACT's Technical and Safety Regulator about relevant technical and safety obligations in preparing the Annual Benchmarking Report, in which case ActewAGL Distribution requested the AER provide it with details of the nature and timing of that consultation, or that it would consult with that Regulator prior to publication of that Report.

The AER did not respond directly to ActewAGL Distribution's questions, in its letter of 17 November 2014, asking whether the AER had consulted with the ACT's Technical and Safety Regulator in preparing the Annual Benchmarking Report, as required for compliance with its obligation under that Clause. There is no mention of such consultation in the draft decision and, as that analysis did not appear in the Draft Annual Benchmarking Report, that consultation could not have occurred in the course of preparing the Annual Benchmarking Report (as the Rules contemplated it would). This is notwithstanding that, for the reasons already discussed, the scheme of the Rules is that the AER will consult with that Regulator in developing the economic

[175] Provided to ActewAGL Distribution by the AER on 8 December 2014, in response to ActewAGL Distribution's request of 5 December 2014 for the information, analyses and models relied on by the AER in making the Draft Decision, and the terms of reference for its benchmarking consultants.

benchmarking techniques to be employed, and analysis to which it will have regard, in making a distribution determination for ActewAGL Distribution.

In correspondence dated 18 November 2014, Ms Paula Conboy, Chair of the AER, purported to respond to this request by informing Mr Michael Costello, CEO of ActewAGL Distribution, that:

> *Following consultation the report has been amended where necessary to address issues raised in submissions, including those submissions made by the relevant technical and safety regulators.*

It is unclear from this statement what steps the AER took to engage with the ACT's Technical and Safety Regulator about relevant technical and safety obligations. Ms Conboy's statement suggests that the AER may have merely invited the ACT's Technical and Safety Regulator to comment on the Draft Annual Benchmarking Report, rather than taking steps to ascertain through engagement with technical and safety regulators the differences in the relevant technical and safety obligations applicable across jurisdictions and the implications of this for required expenditure. It is also unclear whether the ACT's Technical and Safety Regulator made any submission to the AER on the Draft Annual Benchmarking Report; no mention is made of such a submission in the Annual Benchmarking Report itself.

In any event, Clause 8.7.4(b)(2) of the Rules requires the AER to take active steps to ascertain through engagement with technical and safety regulators the differences in the relevant technical and safety obligations applicable across jurisdictions and the implications of this for required expenditure. To the extent that the AER merely invited the ACT's Technical and Safety Regulator to comment on the Draft Annual Benchmarking Report, this would not suffice to discharge the AER's obligation under that Clause.

Ms Conboy's statement would appear to confirm, however, that the AER did not consult the ACT's Technical and Safety Regulator on the adequacy of ActewAGL Distribution's base year opex where adjusted as recommended by Economic Insights on the basis of the additional economic benchmarking analysis included in the Economic Insights Report (but not the Annual Benchmarking Report) for achieving continued compliance with relevant technical and safety obligations.

ActewAGL Distribution contends that, in light of the procedural deficiencies in the AER's development and application of the benchmarking techniques and analysis relied upon in the draft decision, the AER should undertake a further, discrete consultation process in respect of those techniques and that analysis that enables adequate time for their thorough review and assessment before proceeding to rely on them in making its final decision (particularly if the AER intends to rely on them deterministically, as it has done in its draft decision) or, failing that, should not proceed to rely on them in making that final decision.

3.4.4.2 *The draft decision on base year opex is contrary to statutory scheme under the Rules*

ActewAGL Distribution considers that the AER's draft decision on base year opex is contrary to the statutory scheme established by the Rules. Whereas the statutory scheme contemplates that the AER will use ActewAGL Distribution's proposal as the starting point, assess it and, if necessary, make adjustments to that proposal, and will use benchmarking as 'but one tool the AER can utilise to assess NSPs' proposals',[176] the AER has, with only limited exceptions, put aside ActewAGL Distribution's proposed base year opex and instead given primacy to benchmarking analysis in making its decision on base year opex, relying on that analysis almost exclusively to assess ActewAGL Distribution's base opex and deterministically applying it to derive a substitute base opex estimate.

The AER makes numerous references in the draft decision to the adoption of a 'cautious approach' to, rather than a mechanistic, application of benchmarking results, informed by a number of different assessment techniques and its detailed consideration, and the balance, of the qualitative and quantitative evidence before it.[177] In fact, however, the only detailed consideration of ActewAGL Distribution's proposed base year opex that appears in the draft decision relates to the AER's detailed review of labour practices.[178] Section 3.4.4.9 responds directly on this matter and demonstrates that the AER has incorrectly concluded that ActewAGL Distribution is inefficient. The remainder of the techniques employed and evidence considered by the AER is in the nature of benchmarking techniques and analysis, whether the benchmarking techniques and analysis developed by Economic Insights or the 'more simplistic' PPI measures or category analysis, which the AER has concluded have "limited use".[179]

This cannot be reconciled with the statutory scheme established by the Rules. The provisions of Part E of Chapter 6, which specify the procedure for the making of distribution determinations, establish the submission of the regulatory proposal as the starting point for that procedure.[180]

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[176] See Attachment C5, AEMC, 2012, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012,* November, page 107

[177] See, for example, AER, 2014, *Draft Decision ActewAGL Distribution Determination 2014-19 Attachment 7: Operating expenditure*, November, pages 7-17 to 7-19 and 7-33 to 7-34

[178] The AER also conducted a detailed review on ActewAGL Distribution's vegetation management practices in the base year. However, ActewAGL Distribution did not propose a base year approach for vegetation management costs. See section 3.7.

[179] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 32

[180] *National Electricity Rules,* clause 6.8

The ENA made this point in its response to AER Draft Expenditure Forecast Assessment Guidelines where it stated that:

> *the NSP's proposal will be the procedural starting point for the AER to determine an expenditure allowance, and that the NSP's proposal will, in most cases, be the most significant input into the AER's decision.*[181]

Similarly, Clauses 6.5.6(c) and (d) and 6.12.1(d)(4) of the Rules require the AER to assess a DNSP's proposed total forecast opex and provide for it to make adjustments to that forecast only where it is not satisfied that that forecast reasonably reflects the opex criteria. As discussed above in Section 3.2.4, the AEMC affirms the scheme of the Rules disclosed by these provisions, observing that the regulatory proposal is 'the procedural starting point' for the determination of the opex allowance as '[t]he NSP has the most experience in how a network should be run',[182] and that, unless the AER concludes that the regulatory proposal is of no probative value (which it observed would be an unlikely conclusion given the DNSP's knowledge of its own network), 'then the AER should justify its conclusions by reference to it'.[183]

The Rules further disclose that benchmarking is to be used as one only of a number of tools to assess ActewAGL Distribution's base year opex proposal and do not contemplate that such analysis will be given primacy. Benchmarking is the subject of one only of a number of opex factors to which the AER is required to have regard[184] and the AEMC has itself observed that benchmarking is no substitute for the role of a NSP's proposal.[185] While the AER correctly observes in its draft decision that it has a discretion with respect to the relative weight to be accorded to the opex factors,[186] its decision to accord primacy to its benchmarking analysis

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[181] See Attachment C82, ENA, 2012, *Submission on the Draft Guidelines and Explanatory Statement,* September, page 3

[182] See Attachment C5, AEMC, 2012, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012,* November, page 111

[183] See Attachment C5, AEMC, 2012, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012,* November, page 112

[184] *National Electricity Rules,* clause 6.5.6(e)

[185] See Attachment C5, AEMC, 2012, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012,* November, page 107

[186] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-10

almost to the exclusion of ActewAGL Distribution's proposal is an incorrect exercise of discretion and unreasonable in all the circumstances.

The AER does not appear to have concluded in its draft decision that ActewAGL Distribution's proposal as to base year opex is of no probative value (and, in any event, ActewAGL Distribution considers such a conclusion would not be in accordance with law and unreasonable in all the circumstances for the reasons foreshadowed by the AEMC). Accordingly, as required by Chapter 6 of the Rules and contemplated by the extrinsic material, the AER should have justified its draft decision on base year opex by reference to ActewAGL Distribution's proposal. That is, before proceeding to rely on the results of benchmarking analysis, the AER should have undertaken a detailed analysis of the actual expenditure incurred by ActewAGL Distribution in the base year that comprised its proposed base year opex. This is particularly so given the size of the AER's proposed reduction to base year opex justified by reference to that benchmarking analysis and its recognition of environmental variables not accounted for in the benchmarking analysis (discussed further in Section 3.4.4.5).

ActewAGL Distribution does not consider the review of labour practices categories suffices to render the AER's draft decision justified by reference to ActewAGL Distribution's proposal in accordance with the statutory scheme, particularly given the deficiencies in that review identified in Section 3.4.4.9 below. Similarly, Section 3.4.4.10 addresses deficiencies in the AER’s review of vegetation management.

3.4.4.3 *The AER’s mechanistic use of benchmarking is inappropriate*

The AER has applied benchmarking in an inappropriate manner which is contrary to the intented use of benchmarking, fails to recognise the limitations of benchmarking and is in contrast with international precedent. The AER’s application of benchmarking is therefore not in accordance with law. ActewAGL Distribution contends that:

- The primary value of benchmarking, once reliable data sets and models have been established, is to serve as a tool to identify significant areas of expenditure anomaly between businesses which are then subject to further detailed investigation;
- In contrast, the AER’s approach is one that is mechanistic, despite claiming that benchmarking has been used cautiously;

- The AER's mechanistic use of benchmarking in the draft decision is at odds with the intended use of benchmarking foreshadowed by the AEMC, Productivity Commission, the ACCC and the AER itself;[187]
- The AER has failed to recognise the general limitations of benchmarking; and
- Undue weighting that is attached to benchmarking results by the AER to set expenditure allowance is not in line with international best practice.

First, ActewAGL Distribution submits that the primary value of benchmarking, once reliable data sets and models have been established, is to serve as a support tool in identifying significant areas of expenditure anomaly between businesses.

Once these anomalies have been identified further technical engineering analysis can be undertaken to investigate and understand the underlying explanation of the anomaly. Moreover, the data sets and the models themselves will remain in a state of development given the early stages of data collection and the use of benchmarking processes in Australian electricity regulation. Consequently, as the benchmarking results using Australian RIN data do not yet provide robust results the use of benchmarking as a diagnostic tool to identify areas for further detailed investigation rather than as a means of deriving a numeric estimate of efficient expenditure is even more appropriate.

As a result, ActewAGL Distribution has consistently contended that benchmarking cannot be used to drive regulatory allowances, when data and models are still in their infancy. ActewAGL Distribution has stated that:

> *ActewAGL Distribution does not support the use of benchmarking techniques to mechanistically set expenditure allowances. Rather, we support the view of industry, international experts and the Productivity Commission, that benchmarking is a useful 'tool' or 'filter' to be used to identify significant variations between businesses, or particular anomalies in expenditure proposals that require greater scrutiny. In other words, benchmarking should be used to support, rather than drive regulatory decisions.*[188]

[187] The views of these organisations are expanded upon in Attachment C12 Benchmarking background as additional evidence.

[188] See Attachment C13, ActewAGL Distribution, 2013, *Response to Expenditure forecast assessment guidelines issues paper*, March, page 1

ActewAGL Distribution has also expressed this view in a submission to the Productivity Commission's inquiry into electricity network framework regulation.[189]

Second, in contrast with ActewAGL Distribution's position, the AER has applied benchmarking in a mechanistic manner as the primary input into its opex decision.

The AER states several times in its draft decision that it has not applied its benchmarking model mechanistically and refers to the adjustments it has made to the 'raw' benchmarking numbers. The 'adjustments' the AER has made reflect specific factors that it considered should be taken into account (and which are not adequately captured by its model), and are simply amounts added to the initial benchmarking figures. As the base year opex estimate used by the AER can be directly calculated from the initial benchmarking values it is clearly being derived mechanistically. As such, the AER's claim that is has not applied benchmarking mechanistically is incorrect.

Third, the mechanistic application of benchmarking by the AER in the draft decision is in contrast with the use of benchmarking foreshadowed by agencies such as the AEMC, Productivity Commission, the ACCC and the AER itself. A summary of the views of these agencies is provided in Table 3.3.

Table 3.3 Use of benchmarking envisaged by relevant agencies prior to the AER's draft decision

Organisation	Viewpoint on how benchmarking should be used
AEMC	The AEMC has considered the use of benchmarking as part of its 2011 review into the use of total factor productivity[190] and its subsequent rule change in relation to the economic regulation of network service providers.[191] The AEMC concluded that benchmarking is but one tool available to the AER and that the role of the DNSP's regulatory submission remains as the prime information for consideration as discussed in Section 3.2.4.[192] In addition, advice to the AEMC by Prof. Littlechild regarding the rule change identified

[189] See Attachment C14, ActewAGL Distribution, 2012, *Response to Electricity Network Regulatory Frameworks Draft Report,* November, page 23

[190] See Attachment C15, AEMC, 2011, *Final Report: Review into the use of total factor productivity for the determination of prices and revenues,* June

[191] See Attachment C5, AEMC, 2012, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*¸ November, page 107

[192] See Attachment C5, AEMC, 2012, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012,* November, page 107

	the limitations of benchmarking and stressed the importance of its cautious use: *I would say that it would be good regulatory practice for a regulator to consider what if any insights benchmarking could provide in the particular price control under consideration, and to take this into account where appropriate. But as just noted, the circumstances of individual networks can vary greatly, and in my experience there is always an element of unexplained variation where judgement is required. To require the [AER] to undertake benchmarking therefore runs the risk of forcing the regulator to attach more weight to benchmarking than the circumstances allow.*[193]
Productivity Commission	The use of benchmark was then assessed by the Productivity Commission in its 2013 inquiry into electricity network regulatory frameworks. The Productivity Commission found that: [194] *…benchmarking is not yet sufficiently reliable and robust to directly set regulated revenue allowances.* The Productivity Commission also found that benchmarking should not be relied on as the exclusive basis for making a determination but rather should be used as a diagnostic tool: [195] *In any of the next rounds of regulatory determinations, the Australian Energy Regulator should not use aggregate benchmarking as the exclusive basis for making a determination. Instead, it should use aggregate benchmarking as a diagnostic tool in responding to business cost forecasts*
AER/ACCC	The ACCC and AER considered the role of benchmarking via their Regulatory Development Branch and reached the following conclusion: [196]

[193] See Attachment C16, Littlechild, S., 2012, *Advice to the AEMC on Rule Changes*, February, page 16

[194] See Attachment C17, Australian Government Productivity Commission, 2013, *Electricity Network Regulatory Frameworks: Electricity Network Regulatory Frameworks: Productivity Commission Inquiry Report Volume 1*, April, page 29

[195] See Attachment C17, Australian Government Productivity Commission, 2013, *Electricity Network Regulatory Frameworks: Electricity Network Regulatory Frameworks: Productivity Commission Inquiry Report Volume 1*, April, page 324

[196] See Attachment C18, ACCC/AER Regulatory Development Branch, 2013, *Economic Benchmarking Model: Technical Report,* page 20

Economic benchmarking and other assessment techniques will be used to make a preliminary assessment of the proposal. This is a 'first pass' at the expenditure assessment …. It is designed to identify areas of the expenditure forecasts that warrant further investigation.

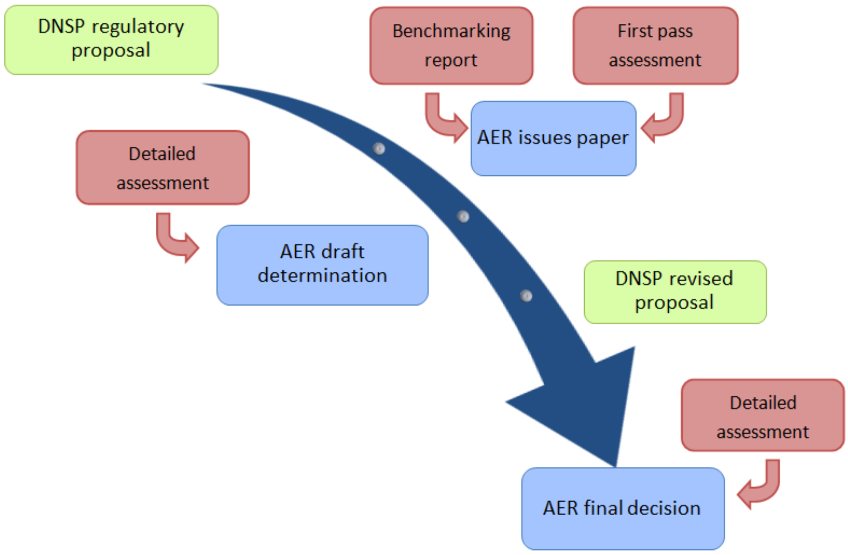
The AER has also indicated in its Expenditure Forecast Assessment Guideline for distribution businesses in November 2013 that the role of benchmarking is to identify areas for further detailed investigation which is counter to the mechanistic approach it then adopted:[197]

For this first pass assessment, we will likely use high level techniques such as economic benchmarking and category analysis to determine relative efficiency and target areas for further review. We will, however, also use these techniques beyond the first pass assessment. The first pass assessment will indicate the extent to which we need to investigate a DNSP's proposal further. Typically, we will apply predictive modelling, trend analysis and governance or methodology reviews before using more detailed techniques such as cost benefit analysis and project or program reviews.

[197] See Attachment C8, AER, 2013, *Better Regulation: Expenditure forecast assessment guidelines for electricity distribution,* November, pages 11 to 12

Furthermore, the process intended by the AER is illustrated in Figure 3.3 which shows the role of benchmarking as an input into more detailed assessment.

Figure 3.3 AER's intended assessment process[198]



As part of the review process, the AER envisaged the use of engineering consultants:

> *This detailed review may involve engineering review of proposed cost categories and/or review and refinement of the assessment techniques used in the first-pass. However, a well defined first-pass assessment methodology could streamline the assessment of opex and capex and facilitate a more targeted use of engineering consultants.* [199]

However, in its draft decision the AER has departed significantly from this process and relied extensively upon its benchmarking results in order to mechanistically derive a numeric estimate of efficient opex. The AER has not undertaken a detailed engineering review of ActewAGL Distribution's operating expenditure and instead relies primarily on the outputs of its benchmarking analysis.

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[198] See Attachment C8, AER, 2013, *Better Regulation: Expenditure forecast assessment guidelines for electricity distribution,* November, page 12

[199] See Attachment C18, AER, 2012, *Better Regulation: Expenditure forecast assessment guidelines for electricity distribution and transmission businesses,* December, page 34

Of the 52 queries received by ActewAGL Distribution, only eight were at least peripherally related to base-year operating expenditure. The AER, in developing its draft decision, has not undertaken any direct consultation with engineering staff from ActewAGL Distribution to attempt to understand the underlying drivers for the anomalies between the AER's econometrics and ActewAGL Distribution's proposal. Instead, the AER has placed primary importance on the outcomes of its benchmarking analysis.

Fourth, the AER has failed to recognise the general limitations of benchmarking and the need for its cautious application rather than the mechanistic use to set regulatory expenditure allowances. These limitations include:

- That the AER has attempted to estimate productivity which it has assumed is equivalent to efficiency. Mr Glyde and Mr Mudge states that they are:[200]

  highly concerned that the AER has effectively conducted an analysis designed to provide one measure of relative productivity and then inferred that the productivity score assessed under this analysis is an appropriate basis to determine the efficient opex of Australian DNSPs. The clear flaw in this approach is that it measures one parameter (productivity) and arbitrarily applies it to determine another variable (efficient opex), without appropriate consideration of the pitfalls in doing so.

- There is no single 'right' benchmarking model. There is no consensus on either the identification or the quantification of inputs and outputs of the electricity distribution industry. For example, while the AER has chosen three output variables (customer numbers, circuit length and ratcheted maximum demand) other regulators adopt different variables, for instance the German regulator uses 11 output variables, while the Swedish regulator uses three variables, including "installed capacity of transformers".[201] This matter is identified by Mr Blair in his expert report where he states: [202]

  > *…academic conversation around this topic illustrates the challenge in applying techniques suited to production scenarios where the outputs can be both defined and measured (bank transactions, airline passenger miles, products from a factory,*

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[200] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 1

[201] See Attachment C19, WIK-Consult, 2011, *Cost Benchmarking in Energy Regulation in European Countries*, December, pages 32 and 51

[202] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, page 11

> *patients treated, etc) to the electricity distribution scenario where products delivered are not so easily counted, let alone identified.*

This view is consistent with the Productivity Commission which states that there are:[203]

> *divergent views about the appropriate inputs and outputs of electricity network businesses.*

This matter relates directly to model specification as discussed further in Section 3.4.4.5 and illustrated in Section 3.4.4.6 where ActewAGL Distribution outlines alternative models which provide differing results to those the AER has relied so extensively upon.

- Failure to take into account dynamic and allocative efficiency. The AER considers the use of benchmarking as primarily assisting in "forming a view on the productive efficiency of distributors."[204] This effectively focuses on estimation of a least cost unsustainable production function. However, a focus on productive efficiency ignores dynamic and allocative efficiency contrary to the NEO and the long term interests of consumers. Mr Houston investigated the role of efficiency in the NEO and states:

  > *the NEO is structured so as to encapsulate all three dimensions of efficiency that are familiar to economists, ie, productive, allocative and dynamic. …by its reference to the 'long term' interests of consumers, the NEO is structured so as to clarify that the balance of emphasis is to be given to the long term, dynamic dimension of efficiency.*

  The importance of appropriately recognising these three elements of efficiency are discussed further in Sections 3.4.4.4 in the discussion of incentives and 3.4.4.5 in relation to establishment of the efficiency frontier.

- Econometric benchmarking that focuses narrowly on opex will not capture the effect of cost allocation between opex and capex. Measures of benchmarking productivity should ideally capture total outputs (opex and capex). As such, the AER's approach potentially distorts the estimation of the cost function as in the long-run, there is a trade-off between the two cost classes, and in the short-run, there are differences in DNSPs approach to cost allocation and capitalisation. To accurately compare the productive efficiency of firms, both cost classes must be taken into account. ActewAGL Distribution discusses this matter further with particular reference to capitalisation policies in

[203] See Attachment C17, Australian Government Productivity Commission, 2013, *Electricity Network Regulatory Frameworks: Electricity Network Regulatory Frameworks: Productivity Commission Inquiry Report Volume 1*, April, page 147

[204] AER, 2014, *Electricity distribution network service providers - Annual benchmarking report*, November, page 10

Section 3.4.4.5. The issue was also identified by Mr Blair in his expert report[205] and Professor Newbery.[206]

- Inadequate adjustment for inclusion of operating and environmental considerations will lead to unreliable results of efficiency. The AER has failed to fully recognise unique environmental factors as discussed further in Section 3.4.4.5.

Fifth, the AER applies benchmarking in a manner inconsistent with international experience. Different international regulators adopt different approaches and models. However, even in jurisdictions where benchmarking has been used for a series of regulatory control periods, no regulator places the same degree of reliance on a single model as the AER. Professor Newbery looks to the examples of Ofgem and Ofwat in the United Kingdom (generally considered leaders intheir sectors[207]) and finds that for which he notes:

> *It is important to bear in mind that both Ofgem and Ofwat consider their proposals as 'packages' (i.e. financing, incentives, expenditure allowance) and that looking at a single 'block' does not tell the whole story of how the allowances are set…*
>
> *In its recently published final proposals for the electricity distribution price control from 2015 (RIIO-ED1), Ofgem focused on total expenditure (totex) allowances and does not provide opex-specific efficiency targets. Ofgem stated that it used a tool-kit approach to benchmarking, recognising that there is no definitive answer for assessing comparative efficiency. It placed a 50% weight on a bottom-up process/ activity assessment of the companies' historical and forecast expenditure. Two totex models were each given 25% weightings. Ofgem noted that the different approaches each have their advantages and disadvantages "[t]he advantage of totex models is that they internalise opex and capex trade-offs, are relatively immune to cost categorisation issues and they give an aggregate view of efficiency…*
>
> *During its most recent price control review (PR14), Ofwat used base-opex and capex models, and totex based econometric models to determine the allowances for companies. Ofwat used two different techniques for its modelling, COLS and RE(GLS) models. All the models*

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[205] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, pages 48 to 50

[206] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, pages 10 to 14

[207] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 44

> *were weighted together before the frontier (upper quartile) was estimated to avoid cherry-picking the efficient companies across the models and setting an implausible target.* [208]

The approach of the AER is in contrast with Ofgem and Ofwat as the AER relies on a single model which it applies in a mechanisitic manner. Neither Ofgem nor Ofwat place such a heavy reliance on an single model despite their extensive experience in the use of benchmarking techniques.

The AER and ACCC Regulatory Development Branch also undertook an investigation of regulatory practices in other countries in regard to benchmarking opex and capex in energy networks. The investigation found that there were a range of benchmarking methods used and that the choice of model appeared to relate to the intended application and data quality and availability. The investigation also noted with respect to the SFA approach adopted by the AER and Economic Insights that: [209]

> *None of the seven international regulators covered in this report has undertaken Stochastic Frontier Analysis (SFA), possibly due to the intensive data requirements of the technique.*

In conclusion, ActewAGL Distribution considers the AER's mechanistic use of benchmarking to be inappropriate. The mechanistic use of benchmarking is counter to the use of benchmarking as a tool to identify areas for further investigation and contrary to the AER's own previous position on its appropriate use. In addition, the AER has applied benchmarking in a manner inconsistent with the intentions of the AEMC, Productivity Commission and the ACCC. It has also failed to recognise its limitations and has applied benchmarking in a manner inconsistent with international precedence, for example, Ofgem only places a 50 per cent weighting on its two totex models in stark contrast to the approach of the AER which relies extensively on the outcomes of a single model. ActewAGL Distribution therefore considers that the AER's mechanistic application of benchmarking is not in accordance with law.

3.4.4.4 *Inconsistency of benchmarking with the regulatory incentive regime*

The AER has abandoned the use of the revealed cost approach to set efficient base year opex and the use of its Efficiency Benefits Sharing Scheme (EBSS). This represents a retrospective change that breaks the regulatory contract, significantly increases regulatory risk and destroys the incentives contained in the regulatory framework. Instead, the AER relies on the outcomes of

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[208] See Attachment C3, CEPA, 2015, *Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, pages 46 to 48

[209] See Attachment C20, AER/ACCC, 2012, *Regulatory Practices in Other Countries: Benchmarking opex and capex in energy networks*, May, pages 2-5

its econometric model as the primary input into the determination of its draft opex allowance and fails to comprehend the impact on incentives this approach entails.

ActewAGL Distribution sought independent advice from Mr Greg Houston on regulatory incentives and the implications of the AER's decision for ActewAGL Distribution and the regulatory framework more broadly. Mr Houston identifies a number of critical implications for incentives to reduce opex arising from the AER's shift to abandon the EBSS. In particular, Clause 6.5.8(c) of the Rules provides detailed guidance as to the incentive regime that is intended to operate for a DNSP in relation to opex. For example, in developing an EBSS, the AER is required to have regard to:

- the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs;
- the need to provide DNSP with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure;
- the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses;
- any incentives that DNSPs may have to capitalise expenditure; and
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

In relation to this, Mr Houston concludes that:[210]

> *In my opinion, the incentive framework implied by the AER's draft decision in relation to ActewAGL departs substantially from these specified requirements.*

Mr Houston also states that his analysis: [211]

> *… shows that the AER's proposed approach to setting the opex allowance and its associated abandonment of the EBSS has profound, negative consequences for the efficiency incentives faced by a DNSP.*

The economic framework that applies to ActewAGL Distribution's electricity network is based on the concept of "incentive regulation".[212] This approach is underpinned by the second RPP in the National Electricity Law:

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[210] See Attachment C1, HoustonKemp, 2015, *Opex and the efficiency benefit sharing scheme*, January, page 22

[211] See Attachment C1, HoustonKemp, 2015, *Opex and the efficiency benefit sharing scheme*, January, page 22

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–

(a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and

(b) the efficient provision of electricity network services; and

(c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

Accordingly, the Rules prescribe an incentive based approach: building blocks with add-ons. The building block approach incentivises DNSPs to outperform the efficient and prudent costs as part of the regulatory determination process. The add-ons complement the building blocks and provide an additional layer of incentives through either requiring, or allowing, the AER to develop and publish an incentive scheme to provide incentives to:

- provide a fair sharing of efficiency gains and losses (Efficiency Benefits Sharing Scheme - EBSS)[213] with regard to providing a continuous incentive to reduce operating expenditure, so far as consistent with economic efficiency;
- maintain and improve performance (the Service Target Performance Incentive Scheme - STPIS)[214] taking into account the need to ensure that the incentives are sufficient to offset any financial incentive the DNSP may have to reduce costs at the expense of service levels;
- implement efficient non-network alternatives, manage expected demand or efficiently connect embedded generators (demand management and embedded generation connection incentive scheme);[215] and
- contribute to the achievement of the national electricity objective (small-scale incentive scheme).[216]

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[212] See Attachment C21, AER, 2012, *AER submission to the Productivity Commission Inquiry to Electricity Network Regulation,* April, page 4

[213] *National Electricity Rules,* clause 6.5.8(a)

[214] *National Electricity Rules,* clause 6.6.2(a)

[215] *National Electricity Rules,* clause 6.6.3(a)

[216] *National Electricity Rules,* clause 6.6.4(a)

The Rules also provides a capital expenditure incentive mechanism, a requirement for the AER to make and publish guidelines and for the AER to have regard to the need to provide effective incentives to promote economic efficiency in the provision of standard control services. The incentive framework reveals the efficient costs of DNSPs.

The AER's June 2008 Efficiency Benefit Sharing Scheme (EBSS) sets out the approach to providing a continuous incentive for ActewAGL Distribution over the 2009-14 regulatory control period to improve the efficiency of its operating expenditure. By being subject to a continuous incentive to reduce expenditure, businesses are provided with a strong incentive to reveal efficient costs. This has been acknowledged by the AER in its 2008 EBSS final decision:[217]

> *In order for the EBSS to provide a continuous incentive, the AER considers forecast opex in the following regulatory control period should be based on actual opex in either the penultimate or antepenultimate regulatory year in the current regulatory control period.*

Similarly the AER also states:

> *Since the EBSS is designed to provide incentives for DNSPs to reveal their efficient level of opex, the AER considers it is reasonable to expect the actual opex in the base year of a regulatory control period to be the best indicator of the efficient level of opex available when determining forecast opex for the following regulatory control period.*

Mr Houston has also investigated these incentives and concluded, in alignment with the AER, that the arrangements create operating expenditure efficiency incentives and that ActewAGL Distribution has had a strong incentive to reveal its efficient opex during the 2009-14 regulatory control period.

ActewAGL Distribution has been operating under this incentive framework since 2009 and has made efficient expenditure decisions with the expectation that this incentive will continue to apply in subsequent periods. During the last regulatory control period ActewAGL Distribution has experienced efficiency "losses". Opex exceeded the forecast allowance for the 2009-14 regulatory control period. However, ActewAGL Distribution considers these expenditures to be efficient and driven by the regulatory incentives of the regime.[218]

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[217] See Attachment C22, AER, 2008, *Electricity distribution network service providers Efficiency benefit sharing scheme: Final decision*, June, page 9

[218] Mr Houston has also investigated situations where a DNSP may not respond to incentives and increase operating expenditure. He identified unforeseen events; investment in future efficiencies; misalignment of operating and capital incentives; and improvements in service quality. See Attachment C1, HoustonKemp, 2015, *Opex and the efficiency benefit sharing scheme*, January, pages 13 to 16

By abandoning the EBSS and the use of revealed cost, the AER's draft decision retrospectively undermines the incentive based framework and creates regulatory risk and uncertainty. This view is supported by Mr Houston's expert report. In particular, he notes that abandoning the EBSS and the incentive arrangements proposed are inconsistent with the NEO, and not in the long term interest of customers because they:

- *undermine the incentive for DNSPs to reduce future opex costs, by discouraging businesses from efficiently incurring expenditure to restructure;*
- *do not provide a continuous incentive when outturn opex is below benchmark levels, and so encourage DNSPs to defer efficiency improvements;*
- *increase the incentive to capitalise expenditure when opex is above benchmark levels while providing an incentive to substitute capex for opex when below benchmark levels;*
- *frustrate the incentive to procure demand management services since the penalty for spending additional opex is over three times greater than the reward offered under the CESS for deferring network investments; and*
- *obstruct the incentive to improve service performance since the penalty for spending additional opex is substantially greater than the reward provided for improved service performance under the STIPS.*[219]

Mr Houston concludes:

> *In my opinion, the efficiency incentives implied by the opex arrangements set out in the draft decision given undesirable weight to short term, allocative efficiency considerations, such that the achievement of long term dynamic efficiency is undermined. Such an outcome cannot be consistent with the NEO and, in particular, its emphasis on the 'long term' interests of consumers.*[220]

Further, Mr Houston states that:

> *In my opinion, an unanticipated, retrospective change to the regulatory framework that imposes a substantial material negative financial loss to a DNSP materially* ***increases the regulatory risk applying to all network service providers. This cannot be consistent with the NEO****. I calculate that, to maintain the intended sharing ratio of 30:70 in net present value terms, would require*

[219] See Attachment C1, HoustonKemp, 2015, *Opex and the efficiency benefit sharing scheme*, January, page 30

[220] See Attachment C1, HoustonKemp, 2015, *Opex and the efficiency benefit sharing scheme*, January, page 30

> *the AER to add $36.7 million (2013-14 dollars) to ActewAGL's 2014-15 revenues.* ***(emphasis added***[221]

In conclusion, the AER's draft decision represents a retrospective change that increases regulatory risk and undermines the incentives contained in the regulatory framework. A direct implication of the increase in regulatory risk is to increase the return demanded by investors and hence the cost of capital to the detriment of consumers.[222] The use of benchmarking as opposed to revealed costs, along with the abandonment of the EBSS, undermines the incentive framework. ActewAGL Distribution will no longer be subject to a regime with symmetry of rewards and penalties and a continuous and constant incentive that exists throughout the regulatory control period.

ActewAGL Distribution considers that the AER fails to fully consider the implications of its draft decision and the perverse incentives it creates, and runs counter to the incentive arrangements the AER implemented in preparation for the last regulatory control period. Moreover, the AER's focus on short term productive and allocative efficiency results in an unsustainably low opex allowance which is contrary to the NEO and long term interests of consumers as discussed further in Section 3.4.4.5 in relation to the efficiency frontier.

3.4.4.5 *Technical flaws in the AER's econometric modelling*

The previous Sections have illustrated how the AER has failed to adopt a suitable procedure for developing its benchmarking approach, has failed to use ActewAGL Distribution's proposal as the starting point for its assessment, has inappropriately applied benchmarking mechanistically and has adopted a scheme that destroys many of the existing regulatory incentives.

Despite these flaws, the AER has placed primacy on the outcomes of its econometric benchmarking to conclude that ActewAGL Distribution's base year opex as set out in the regulatory proposal is materially inefficient. However, due to the numerous technical flaws, the AER has reached this conclusion in error and it is therefore inappropriate and inconsistent with the requirements of the Law and Rules. The AER must therefore abandon its current use of benchmarking to determine an estimate of base year opex and adopt an approach based on ActewAGL Distribution's revealed costs.

The technical flaws relate to the following:

- the Australian data set used by the AER cannot be relied upon;

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[221] See Attachment C1, HoustonKemp, 2015, *Opex and the efficiency benefit sharing scheme*, January, page 29

[222] See Attachment C1, HoustonKemp, 2015, *Opex and the efficiency benefit sharing scheme*, January, page 26

- the inclusion of international data is inappropriate and limits the conclusions that can be drawn from the results;
- the model selection by the AER has not been justified, and alternative model specifications would lead to different results for ActewAGL Distribution;
- important environmental variables have been omitted from the AER's econometric model and the AER's post-modelling adjustments to efficiency adjustments are incorrect, arbitrary and unsubstantiated;
- the AER's efficiency frontier adjustment from 2009 to 2013 has been applied incorrectly; and
- the efficiency frontier is established incorrectly by the AER.

These matters are discussed throughout the remainder of Section 3.4.4.5. These flaws support ActewAGL Distribution's contention that the results of the AER's benchmarking analysis are not robust and should not be used in a mechanistic way to derive the base year opex forecast, reinforcing the concerns set out in Section 3.4.4.3.

The Australian data set used by the AER cannot be relied upon

The Australian Regulatory Information Notice (RIN) dataset used by the AER and Economic Insights is immature and cost data has been reported on an inconsistent basis, leading to an 'apples with oranges' comparison of DNSPs. The AER's data collection combined with the AER's benchmarking analysis can be characterised as 'garbage in garbage out'. The AER can therefore not rely upon the results of the modelling and its conclusions represent a manifest error.

The AER recognises that:

> *When there is uncertainty about the quality of the data and the appropriate model specification, and where different specifications provide different results, it may be necessary to use the results cautiously. […]The appropriate benchmark may also differ depending on the sensitivity of benchmarking results to technique and model specification. When there is uncertainty about the appropriate model specification and different specifications provide different results, it may be necessary to use the results cautiously.*[223]

ActewAGL Distribution agrees and notes that the circumstances identified by the AER above apply in the current case, namely uncertainty about the quality of data and a lack of robustness of the results to different model specifications. This Section outlines these concerns as follows:

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[223] See Attachment C9, AER, 2013, *Explanatory Statement: Expenditure Forecast Assessment Guideline,* November, pages 127-8

- the RIN data is immature; and
- the RIN data is incomparable due to the application of different Cost Allocation Methodologies and internal business practices across DNSPs.

The AER has used the RIN data and attempted to create a time series of data for the period 2006 to 2013. However, this data was created in a single year with early year data backcast. As such, the data does not represent a consistent time series but rather an historical 'best guess'. The importance of collection of data on an annual basis has been recognised by the AEMC which noted that the AER's historical approach does not represent best practice.[224]

The immaturity of the data set raises normalisation concerns. Mr Blair observes there is a significant different in the approach of Ofgem and the AER noting:

> *The OFGEM approach is also based on many years of regulatory reporting to a consistent format and common reporting timeframes (i.e. the lack of a staggered reporting and/or regulatory determination cycle, as exists in Australia), which are more favourable conditions for data accuracy.*[225]

Similarly, Professor Newbery's states:

> *Even before normalising costs, regulators in other jurisdictions, e.g. Ofgem and Ofwat, have spent many years establishing and refining reporting requirements to ensure that activity level and/ or cost categories are reported on a like-for-like- basis. For instance, Ofgem's regulatory reporting guidelines (RIGS) specify that painting of a transformer is not a refurbishment activity, but should be reported as opex. This means that when Ofgem conducted its unit level benchmarking, as part of RIIO-ED1, it had greater confidence in the comparability of costs and volumes across the network operators and knew that the aggregate level costs, e.g. opex, asset replacement expenditure, were built up on this basis.*[226]

The immaturity of the AER's approach is reflected by the AER's requirement that opex be reported in accordance with each DNSP's cost allocation method (CAM) resulting in incomparable data.

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[224] See Attachment C5, AEMC, 2012, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012,* November, page 108

[225] Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER,* January, page 23

[226] Attachment C3, CEPA, 2015, *Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 13

This incomparability of data between businesses is recognised by Economic Insights who attempt to address the issue through various limited before modelling adjustments to Endeavour Energy, Ergon Energy and Essential Energy[227] as well as business specific after modelling adjustments.

These adjustments are insufficient as evidenced by the AER's post modelling adjustments for different levels of capitalisation, different control services, taxes and levies and occupational health and safety regulations. Professor Newbery considers, given the magnitude of the adjustments proposed, it would be more appropriate to make these adjustments before modelling as the inconsistent data is likely to affect the modelling.[228] Mr Blair agrees that it is more appropriate to adjust the input costs that correct the output results.[229] Indeed Professor Newbery finds that normalising for these differences prior to modelling leads to a different efficiency target for DNSPs.[230]

A major driver of the incomparability issues it the application of different cost allocation methods and internal business practices across DNSPs. Professor Newbery notes that:

> *After reviewing the opex data used in the modelling it appears that capitalisation policy is one factor that can and should be adjusted for across the industry before any modelling. The need for this stems from the AER's reporting guidelines for the RINs as they allow DNSPs to report costs using their own cost allocation methodology (CAM). For network operating costs (i.e. those that are benchmarked) the AER specifically instruct: "Opex must be prepared in accordance with DNSP's Cost Allocation Approach … for the most recent completed Regulatory Year …" The issues this raises for comparability purposes was further highlighted by the AER themselves in their "Overheads and accounting issues" workshop in 2013. They specifically note "discretion in expensing/capitalisation" and "lack of comparability" as problems.*[231]

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[227] Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 10

[228] Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 11

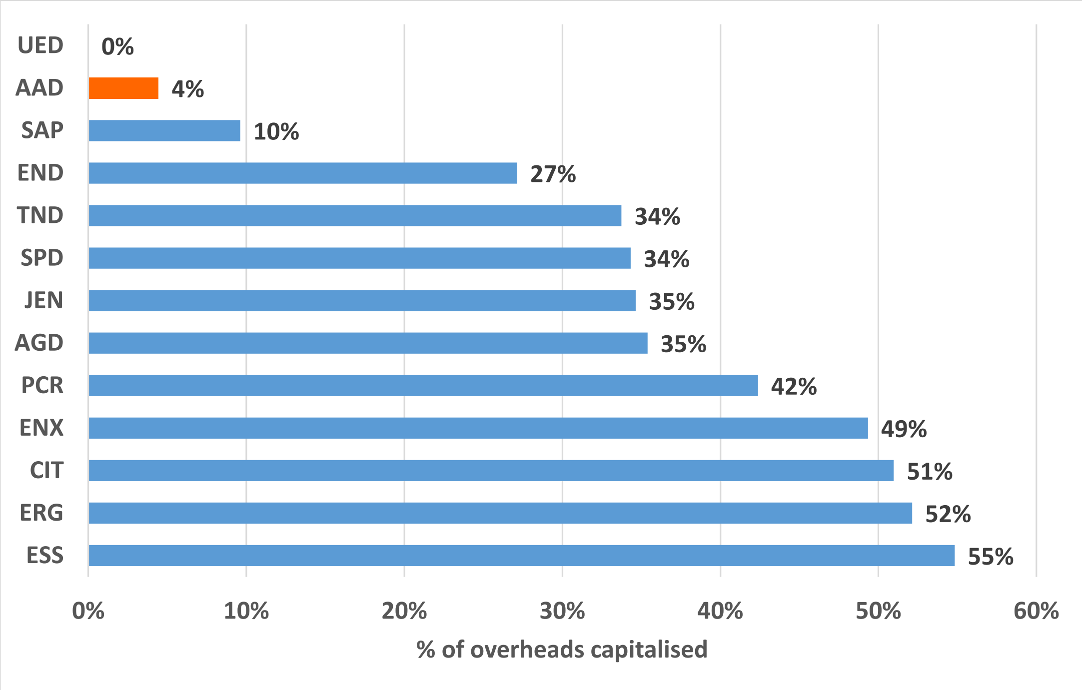
[229] Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER,* January, page 23

[230] Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January , page vi

[231] Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January , page 11

The magnitude of the cost allocation methods is seen in Figure 3.4, which shows the significant divergence in reported average capitalisation of overheads across the DNSPs where ActewAGL Distribution capitalises a significantly lower proportion of overheads relative to other businesses. The effect of lower capitalisation of overheads is that these costs are allocated to opex, thus artificially inflating the relative level of ActewAGL Distribution's opex in comparison to its peers. These differences are unrelated to the underlying efficiency of the businesses.

Figure 3.4 Capitalisation of overheads based on RIN data[232]



ActewAGL Distribution conducted a further high level analysis of the allocation of corporate and network overheads of ActewAGL Distribution with Citipower, Powercor, SA Power Networks, Jemena and United Energy over the 2008-09 to 2012-13 period. Applying the average capitalisation rates of these DNSPs results in a $50 million increase in capex, as shown in Table 3.4, and a corresponding decrease of $50 million in opex for ActewAGL Distribution. This large change shows how different cost reporting and business practices render the data incomparable.

[232] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 12

Table 3.4 The impact of different CAMs and business practices on reported overheads over the 2008-13 period

	Total overheads	Capex %	Average capitalisation of benchmarked[a] DNSPs	Benchmarked capex equivalent	Capex change
Network overheads	140,012	0%	26%	36,058	36,058
Corporate overheads	79,757	12%	30%	23,692	13,983
Total overheads	**219,769**	**4%**	**27%**	**59,750**	**50,040**

[a] Citipower, Powercor, SA Power Networks, Jemena United Energy

ActewAGL Distribution is of the view that the unaccounted for differences based solely on internal practices unrelated to underlying efficiency seriously disadvantage ActewAGL Distribution in comparison with other DNSPs.

Noting that ActewAGL Distribution's allocation of overhead appeared to be different than many other DNSPs, in 2012-13, ActewAGL Distribution engaged McGrathNicol to review ActewAGL Distribution's CAM.[233] This resulted in a recommendation to change ActewAGL Distribution's CAM. As a result, from 1 July 2014 ActewAGL Distribution is applying a new CAM (the new CAM was approved by the AER in 7 June 2013). The new CAM allocates shared costs to a significantly greater degree to projects using an allocation methodology, that is more consistent with other utilities, using causal allocators except to the extent that the shared cost is immaterial and a causal relationship cannot be established.

The effect of the new CAM on the base year (2012/13) is $7 million (when a change in the corporate costs allocation method is netted off). Also, in its 3 October 2014 response to the AER, ActewAGL Distribution drew the AER's attention to the fact that it leases its vehicles and computers which is in contrast to other businesses. The change in the CAM and the leasing of vehicles and computers make up $10 million in ActewAGL Distribution's base year as shown in Table 3.5.

[233] See Attachment C79, McGrathNicol, 2012, *Review of Electricity Networks' Cost Allocation Methodology*, June

Table 3.5. CAM and capitalisation effects on ActewAGL Distribution's base year

Item	Description	Financial effect
CAM	New CAM introduced on 1 July 2014	Net effect on 2012/13 of $7m
Leasing of vehicles and computers	Unlike DNSPs in NSW and Victoria, ActewAGL Distribution's vehicles are leased on an operational basis (rather than finance lease)	~$3m in 2012/13

Applying the new CAM means that if more of ActewAGL Distribution's cost pool was capitalised, even more of the shared costs would be allocated to the capital expenditure projects. The impacts referred to above of $10 million in the base year are therefore very conservative and most certainly underestimate the full impact of ActewAGL Distribution's lower capitalisation level.

ActewAGL Distribution also considers that the AER has omitted to take into account and adjusted for some significant non-recurring items that ActewAGL Distribution incurred in 2012/13. These were specified in an information request response to the AER on 3 October 2014. The non-recurring items identified are shown in Table 3.6.

Table 3.6. Non recurring items incurred in 2012/13

Item	Description	Financial effect
Vegetation management	ActewAGL Distribution experienced a material increase in vegetation management costs in 2012/13 following two years of above average rainfall.	$1.9m in 2012/13
Comcare exit fees	Exit fee for the decision of ACTEW Corporation to exit the ACT Government's Comcare arrangements.	$1.8m in 2012/13
Energy industry levy	An ACT specific fee to cover the costs of regulation in the ACT.	$0.7m in 2012/13
Under-recovery of capex	In 2012/13, ActewAGL Distribution under recovered its cost pool resulting in higher allocation to opex.	$2.9m in 2012/13

These non-recurring items and CAM make up a substantial part of ActewAGL Distribution's operating expenditure in the base year and the AER should therefore have made adjustments to the data set before undertaken its modelling. As a result of the difference in capitalisation approaches, and as noted above Professor Newbery in his analysis, there is a need to make an explicit adjustment to the data set to account for different capitalisation policies between businesses.

The need for Professor Newbery to make this adjustment highlights one significant inconsistency in the manner in which data is collected by the AER and results in the RIN data not being comparable across the Australian businesses. ActewAGL Distribution also still considers that there is further substantial evidence indicating that ActewAGL Distribution capitalises less than other DNSPs. This is discussed further in the expert report from Mr Glyde and Mr Mudge with particular reference to operating leases, capitalisation practices, pole top structures, network overheads and corporate overheads.[234]

Inclusion of international data is inappropriate and limits the conclusions that can be drawn from the results

Economic Insights identified that the SFA econometric model was not robust using Australian RIN data.[235] To overcome this, the Australian data set was augmented with international data from Ontario Canada and New Zealand.

However, the international data is not comparable with that from Australia and the inclusion of the international data swamps the Australian data. Therefore, the conclusions of the AER's econometric modelling cannot be relied upon.

International data was added to the Australian data set despite significant differences such as those identified by Economic Insights:[236]

> *…one difference between Australia and New Zealand and Ontario is that New Zealand and Ontario both have a smaller number of larger DNSPs and a large number of small DNSPs*[237]

Mr Glyde and Mr Mudge reviewed the differences between the businesses and note:[238]

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[234] Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, pages 75 to 86

[235] Economic Insights, 2014, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November, page 28

[236] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, pages 14 to 18 and Economic Insights, 2014, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November, page 30

[237] Economic Insights, 2014, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November, page 30

> *…given that the SFA CD model is a 'one size fits all' approach, we are concerned about the lack of homogeneity between DNSPs on the factors that have been determined to be the most critical attribute in determining efficiency*

In an attempt to make the data sets comparable so that the data reflects differences in operating and environmental conditions, Economic Insights have adjusted the Ontario and New Zealand data by making data adjustments and introducing a dummy variable. Professor Newbery identifies major concerns with their comparability. With respect to country-specific adjustments, Professor Newbery states:

> *The NZ dataset was built up by Economic Insights themselves, while being based on data collected by the NZ Commerce Commission. In a productivity workshop in May 2014 they note that opex needs "uniform treatment of asset refurbishment and allocation of corporate overheads,"[239] and it constructed opex in such a way as to try to control for this. As noted already, this is something that Economic Insights did not do to the RIN data.[240]*

In relation to the use of a dummy variable, Professor Newbery states that the approach of Economic Insights does not appropriately account for the differences between countries:

> *Including a dummy variable in the model specification does not necessarily control for these within and across country differences…*
>
> *A proper econometric analysis is more complex than this and should take account of country-specific slopes, which will require more variables to take this into account…*
>
> *This analysis indicates that there is a different relationship between opex and the cost drivers (customer numbers, circuit length and ratcheted maximum demand) across the countries/ regions and Economic Insights has not controlled for these differences.* [241]

A further example of this data non-comparability is taken from the Ontario Distribution Sector Review Panel which raises specific concerns with the non-comparability of its own Ontario data:

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[238] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 35

[239] See Attachment C25, Economic Insights, 2014, *Productivity Analysis of Electricity Distribution (Commerce Commission Workshop)*, May, slide 26

[240] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 15

[241] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, pages 15-17

Even though the operating costs of small LDCs [local distribution companies] are generally higher, they would be even greater if they incorporated the full cost of distributing low-voltage power to customers.

…small and mid-sized LDCs are charged for the use of the transformer stations and other distribution assets required to serve their customers. LDCs do not typically reflect these charges in the standard operating and capital costs reported to the OEB, leading to understated OM&A totals, though they do ultimately pass these transformation and low voltage distribution costs on to their customers through a separate recovery mechanism. [242]

Mr Glyde and Mr Mudge identify that the Ontario Electricity Distribution Sector Review Panel does not even consider that the Ontario data is internally comparable. They note:

> *With regard to the Ontario data, the Ontario Electricity Distribution Sector Review Panel does not consider its DNSPs or industry structure is comparable to other provinces within Canada or states in Australia and has recently determined that there is a need to consolidate the existing DNSPs* [243]

Mr Glyde and Mr Mudge state that:

> *the AER has clearly not demonstrated that the Ontario DNSPs or the New Zealand DNSPs are comparable to AAD or the other Australian DNSPs*[244]

In addition, Economic Insights have used data from the New Zealand Commerce Commission (NZCC), but have failed to recognise that the NZCC itself cannot rely on the use of benchmarking to set starting values:

> *The Commission may not, for the purposes of this Section, use comparative benchmarking on efficiency in order to set starting prices, rates of change, quality standards, or incentives to improve quality of supply.*[245]

Of greatest concern is the fact that the inclusion of international data swamps the Australian data. Professor Newbery identifies that as the international data provides significantly more data

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[242] See Attachment C26, Ontario Distribution Sector Review Panel, 2012, *Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First*, December, pages 12 to 13

[243] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 102

[244] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 103

[245] *Commerce Amendment Act 2008* (New Zealand) Sec. 52P

points, the international data has a greater influence on the coefficients of the regression analysis than the Australian data. His analysis also indicates that there are different cost drivers across the countries and regions and that Economic Insights have not controlled for these differences.[246]

Mr Blair identifies that the use of the international data also limits the number of environmental variables that can be considered to those which are common across the data sets. Due to the use of the international data, the only environmental variable used to distinguish between businesses is the share of underground network.[247] The importance of satisfactory variables is discussed further below in the discussion of omitted environmental variables.

The overall conclusion that the data cannot be used in the manner adopted by the AER and Economic Insights is supported by Professor Newbery who states:

> *given the lack of scrutiny and difficulties in using international data, it is my opinion that Economic Insights' use of Ontario and NZ data is inappropriate as a supplement to the AER's RIN database.*[248]

In conclusion, the importance of a robust data set cannot be overstated. Professor Newbery states:

> *It goes without saying that robust benchmarking depends on reliable and relevant data, combined with a detailed understanding of the available data*[249]

However, it is clear that the data set adopted by the AER suffers from a number of serious flaws. As such, and consistent with the AER's own position that when there is uncertainty about the quality of the data it may be necessary to use the results cautiously, ActewAGL Distribution does not consider that the current data set can be relied upon as the basis for the AER's analysis and subsequent conclusions.

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[246] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, pages 14 to 18

[247] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, page 29

[248] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 18

[249] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 9

The model selection has not been justified

The AER has failed to justify its model selection. Although the AER claims that it has tested various models, this is misleading and does not recognise that there is no one 'right' model. In addition, it has not provided adequate explanation of the reasons behind the rejection of alternative models and adequate reasoning for its final model selection.

First, the AER expresses its view in several places in the draft decision that it has confidence in its benchmarking results as it has used several different models. For example:

> *We are in a position to comment upon its reliability for assessing base opex now that we have several benchmarking techniques available to us. We consider that they are reliable. We have multiple techniques and their results support each other.*[250]

> *The results of our analysis are consistent and robust*[251]

The AER's view that the benchmarking results are robust has in turn informed its view that the results are suitable for forming the basis of its estimate of an efficient base year opex allowance.

The AER based its draft decision on advice from Economic Insights that the economic benchmarking results from four different models are robust and reinforce each other.[252] However, Mr Blair identifies that the four models cited are in reality variants of a single model specification:[253]

> *The four models cited by the AER in the determination are each variants of a single model specification*

It is therefore unsurprising that the results from the related models are similar. Mr Blair also notes that insufficient alternative models have been tested and applies the Bauer consistency criteria to a range of alternative models including the results from the Pacific Economics Group model (conducted on behalf of the AER), results from the models relied upon by the AER and alternative DEA, SFA and OPEX MPFP models the AER could have considered. The analysis

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[250] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-42

[251] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-42

[252] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-28

[253] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, page 35

indicates a lack of consistency and that the selection of different models and assumptions results in different outcomes and rankings of businesses.[254] Mr Blair's expert report describes this in further detail.

Second, the AER has placed an undue reliance on a single model specification without adequately realising that there is no single 'right' model. With respect to the range of models that could be adopted, Mr Blair notes:

> *Each technique will provide different answers, and often selection of combinations of method, technique and model specification is driven by the available data and other constraints*[255]

This view is consistent with the Productivity Commission:

> *The literature on benchmarking is confused. There are … multiple methods for benchmarking, with little consensus about which is best*[256]

In 2009 Economic Insights concluded that in the Australian electricity industry there is likely to be sensitivities to the specifications chosen:

> *Based on our findings for electricity and gas distribution in Victoria, we conclude that TFP analyses of Australian energy distribution systems will be relatively sensitive to the output and input specifications chosen, the time period examined and the method used to calculate growth rates.* [257]

Similarly, Professor Newbery identified that the benchmarking models (using only the Australian RIN data) are very sensitive to the model's specifications, remarking that:

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[254] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, pages 30 to 31 and 35 to 37

[255] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, page 13

[256] See Attachment C17, Australian Government Productivity Commission, 2013, *Electricity Network Regulatory Frameworks: Electricity Network Regulatory Frameworks: Productivity Commission Inquiry Report Volume 1*, April, page 147

[257] See Attachment C27, Economic Insights, 2009, *Energy Network Total Factor Productivity Sensitivity Analysis*, June, page 24

> *The sensitivity of the inefficiency results to the specification of the modelling indicates that significant caution should be placed on the results of* ***any one*** *specification as it is unlikely to control for all the differences between the companies.*[258] ***(emphasis added)***

Importantly, Professor Newbery's modelling results result in efficiency rankings and implied base year opex changes for ActewAGL Distribution that are markedly different from those provided by Economic Insight's models. This is shown in Section 3.4.4.6 and discussed in detail in his expert report.

The AER has naturally found consistent results when it adopts a narrow set of explanatory variables and applies its modelling techniques. The outcome is effectively variants of the same model specification that are heavily influenced by international data. Economic benchmarking models using different techniques, specifications and different sets of data (i.e. excluding inappropriate international data) are likely to provide different results as identified by Professor Newbery. As a result, the robustness of the results from the modelling done by Economic Insights and relied upon by the AER is misplaced.

The AER has also failed to provide adequate explanation as to why it has discarded alternative models and its decision to rely extensively on a single model. Mr Blair states that:[259]

> *The AER has not only placed disproportionate weighting on a single top-down model, but it has not taken into consideration other models available to it which cast significant doubt on the reliability of the results derived from its preferred model. This includes the modelling and results presented to it by another consultant, Pacific Economics Group. Better regulatory practice dictates that an approach that balances the outcomes of a number of different models is appropriate, as it recognises that each model exhibits some level of bias. Therefore:*
>
> *1. Disproportionate weight should not be placed on any single model; and*
>
> *2. Where inconsistency in results exists, models should be combined in some way that at least mitigates the potential for bias in a single direction.*

Mr Blair also notes that the AER has shifted the goal posts in relation to its preferred econometric model. Mr Blair states that while industry was consulted on earlier versions of the AER preferred models: [260]

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[258] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, pages 33 to 34

[259] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, page 38

the significant changes that have occurred since the Guideline's release are consequential to the NSW and ACT determination and have not been distributed for consultation. We note that:

1. The MTFP specification has been changed twice - firstly the preferred and alternative specifications from the Expenditure Forecast Assessment Guideline were discarded when the results were rejected by Economic Insights and then the specification was modified between the draft annual benchmarking report and the NSW and ACT draft decision; and

2. The techniques of SFA and OLS were not communicated to the businesses as the preferred techniques until they appeared in the supporting documentation of the NSW and ACT draft decision.

The delay in the final benchmarking report has also provided little opportunity for the NSW and ACT businesses to respond other than in the context of the revised regulatory proposal. We consider that the introduction of SFA and the international data associated with it, combined with the level of reliance and deterministic manner in which it has been used, contradicts the AER's own Guideline [Expenditure Forecast Assessment Guideline]

ActewAGL Distribution considers that, within the context of the numerous changes to the AER's preferred model, there can be little confidence in the current model upon which the draft decision is based.

In conclusion, ActewAGL Distribution considers that the AER has failed to justify and scrutinize its model selection, and has placed too much reliance on a single model specification despite alternative models producing differing results. This has led the AER to conclude in error that the results from its benchmarking analysis are sufficiently robust to be able to conclude that ActewAGL Distribution's base year opex is inefficient.

Important environmental variables have been omitted from the econometric model, and the AER's post-modelling adjustments to compensate for these variables are arbitrary and unsubstantiated

In this Section, ActewAGL Distribution submits that the AER:

- Should have applied adjustments to the full data set before the econometric modelling was undertaken rather than as an ad-hoc after the fact adjustment;
- Failed to include a range of important environmental variables in its econometric model; and

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[260] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, page 27

- In an attempt to compensate for this shortcoming, makes a series of arbitrary and unsubstantiated post-modelling adjustments.

Post-modelling adjustments

At first glance it seems reasonable to an uninformed audience that Economic Insights has indeed been cautious because it adjusts ActewAGL Distribution's efficiency results for environmental factors. However, ActewAGL Distribution's experts have each independently confirmed that the AER approach to adjustments for environmental factors post-modelling is inconsistent with international best practice.

Adjustments, where required, should be made before modelling, by normalising the data set, rather than as an after modelling adjustment. Professor Newbery concludes that it would be more appropriate to make the adjustments before the modelling as inconsistent data may be affecting the modelling:

> *Economic Insights has taken account of these adjustments and proposed that the frontier for AAD could be adjusted by 30% as a result. While I do not disagree that adjustments should be made where data are inconsistent, given the magnitude of the adjustments proposed by Economic Insights I consider that it would be more appropriate to make these adjustments before modelling (which would be consistent with the adjustments used for END, ERG and ESS), as the inconsistent data are likely to affect the modelling.*[261]

Moreover, Professor Newbery identifies that simply the order in which the AER makes its adjustments, i.e. before modelling rather than after modelling, affects the result:

> *Even normalising for differences identified by Economic Insights/ AER prior to modelling leads to a different efficiency target for the DNSPs.*[262]

Professor Newbery also notes that making adjustments after the modelling is not in line with the approach used by Ofgem.[263] Mr Blair concurs noting that it:

> *"…is more appropriate to adjust the input costs, than attempt to correct the output results."*[264]

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[261] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, pages 10-11

[262] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 34

[263] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 13

In addition the process of arbitrary adjustments after the modelling has been completed undermines the sophistication of the overall approach.

> *It is worth noting that when regulatory judgement is applied to the frontier after it is estimated via SFA it calls into question why this more complex and less transparent technique was chosen in the first place.*[265]

Similarly, Economic Insights have previously identified the importance of making data adjustments before modelling to account for differences between businesses to allow application of robust modelling:

> *Operating environment conditions can have a* ***significant impact*** *on network costs and productivity and in many cases are beyond the control of managers. Consequently, to ensure reasonably like–with–like comparisons it is desirable to 'normalise' for at least the most important operating environment differences. …* ***Differences in operating environment conditions are likely to affect achievable productivity growth rates as well as achievable productivity levels****.* [266] ***(emphasis added)***

However, while Economic Insights have recognised the importance of making adjustments to data before modelling to create a comparable data set, they have failed to do so in their work for the AER as part of the draft decision.

Omission of environmental variables

The econometric benchmarking model developed by Economic Insights and relied upon by the AER incorporates only a single environmental variable, proportion of underground cable, to capture the operating environment differences between all businesses.[267] Economic Insights explained that it was forced to adopt a single operating environment variable due to the lack of comparable data available from Ontario.[268] While the econometric model also includes customer

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[264] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, page 23

[265] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 38

[266] See Attachment C28, Economic Insights, 2009, *Assessment of Data Currently Available to Support TFP–based Network Regulation*, June, page 14

[267] The AER has made a series of ex-post adjustments to attempt to capture additional differences unique to ActewAGL Distribution. These have been applied incorrectly and are discussed later in this section 3.4.4.5.

[268] Economic Insights, 2014, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November, page 32

numbers, circuit length, and ratched maximum demand, these do not capture environmental differences in the nature of DNSPs networks.

The single environmental variable of proportion of underground cable is unable to capture the differences between DNSPs. Despite this the AER has relied upon the outputs of the model to conclude that ActewAGL Distribution's raw efficiency score compared to the frontier dictates a reduction to ActewAGL Distribution's base opex of 61 per cent, or a CD SFA initial value of $26 million ($2013/14). The data set and modelling upon which this conclusion is based is fundamentally flawed as the model excludes the necessary environmental variables to capture fully the characteristics of ActewAGL Distribution.

The AEMC has noted that circumstances exogenous to a DNSP should be generally taken into account whereas endogenous circumstances[269] should generally not be considered by the AER in undertaking a benchmarking exercise.[270] ActewAGL Distribution agrees. Accordingly, ActewAGL Distribution has urged the AER to more fully consider environmental factors that are beyond the control of DNSPs.[271]

The importance of explicitly accounting for environmental factors as part of the modelling was also identified previously by the ACCC and AER Regulatory Development Branch which states:[272]

> *…in practice, where more diverse NSPs might be included for economic benchmarking it would be necessary to explicitly model the impact of key operating environment factors that may affect NSP performance.*

Similarly, as highlighted in submissions to the Productivity Commission, ActewAGL Distribution considers that to be robust and informative benchmarking should recognise and quantify the impact of uncontrollable factors associated with the physical and institutional environment and historical circumstances, as well as controllable drivers of cost differences such as differences in

[269] The AER has implicitly taken endogenous factors (such as capitalisation) into account due to insufficient data normalisation. This is discussed earlier in this section.

[270] See Attachment C5, AEMC, 2012, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, November, page 113

[271] See Attachment C28, ActewAGL Distribution, 2014, *Response to the AER's Draft Annual Benchmarking Report,* September, page 12

[272] See Attachment C18, ACCC/AER Regulatory Development Branch, 2013, *Economic Benchmarking Model: Technical Report,* page 5

accounting treatments and differences in work practices and operating techniques.[273] This consideration was based on experience during the 2009-14 distribution determination where the differences between firms was not controlled for and resulted in misleading and biased results. Although the AER's consultants recognised that there may be some unique cost drivers and less capitalisation these issues did not factor into the benchmarking analysis. ActewAGL Distribution was able to demonstrate that quantifying just one of the unique cost drivers, the leasing of some assets which is treated as capital expenditure by other firms, significantly altered the results.[274]

The AER has also recognised the importance of including exogenous factors and states:[275]

> *We are satisfied that the benchmark comparison point will result in a total forecast opex estimate that reasonably reflects the opex criteria, subject to accounting for any exogenous factors not captured by benchmarking.*

Despite this, only a single environmental variable has been included in the AER's preferred model. In modelling only a single environmental consideration, underground cables, the AER's model assumes that the only other reason for cost differences is inefficiency, leading to an overestimation of efficiency gaps.[276] In particular Mr Blair identified that networks in favourable operating conditions will appear efficient while those in challenging conditions will appear inefficient.[277]

Failing to include environmental variables leads to a model that is not reflective of industry costs. This is shown by Mr Blair who examines the link between cost categories and the variables included in the AER's preferred model[278] and which is reinforced by Mr Shuttleworth who comments that:

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[273] See Attachment C29, ActewAGL Distribution, 2012, *Response to Productivity Commission Electricity Network Regulation Issues Paper*, April, page 3

[274] See Attachment C29, ActewAGL Distribution, 2012, *Response to Productivity Commission Electricity Network Regulation Issues Paper*, April, page 2

[275] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-39

[276] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, pages 42 to 43

[277] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, page 42

[278] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, page 40

Until anyone can claim with certainty that a benchmarking model has capture every possible cost driver, it is incorrect and misleading to ascribe the residual to ''inefficiency'', or to describe the benchmark as a measure of ''efficient costs''. […] Thus, when regulators use the results of benchmarking as a reason to disallow a proportion of total costs (or of a particular subset of costs), they are in fact acting on an arbitrary basis without proper evidence. [279]

This has also been recognised by Economic Insights in 2010 in comparing a gas distribution business in a unique operating environment who noted that:

However, its operating environment conditions are so different to those of the other included GDBs that it is difficult to establish whether or not Envestra Qld is operating efficiently based on this comparison. To do this we would need to either include other small GDBs operating in a subtropical environment or undertake econometric adjustments for operating environment conditions. [280]

The econometric model is highly sensitive to the manner in which environmental factors are taken into account. Mr Blair states:[281]

Whilst Economic Insights have incorporated the share of network underground directly into the cost function, another equally valid technique is to adjust the error term (and therefore the measure of technical inefficiency) for the influence of the environmental variable. Whilst the choice of which method to use is a largely philosophical one, results suggest that whilst benchmarking rankings stay the same, estimates of inefficiency can vary significantly between the two techniques.

Mr Blair points to previous work by Tim Coelli, a member of the Economic Insights team, in the airline industry where he found:[282]

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[279] See Attachment C30, Shuttleworth, G., 2005, Benchmarking of electricity networks: Practical problems with its use for regulation, vol.13, September, page 315

[280] See Attachment C31, Economic Insights, 2010, *The Productivity Performance of Envestra's South Australian and Queensland Gas Distribution systems*, September, page 39

[281] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, page 41

[282] See Attachment C32, Coelli, T., Perelman, S. and Romano, E., 1999, *Accounting for Environmental Influences in Stochastic Frontier Models: With Application to International Airlines,* Journal of Productivity Analysis, vol. 11, page 271

… we are comforted to find that the ranking of efficiencies do not vary greatly with the method selected but are concerned to find that the sizes of the estimated efficiencies do differ significantly.

To test the sensitivity of the results with respect to how the environmental factor of the extent of undergrounding is taken into account, Mr Blair:[283]

re-ran the SFA model with the environmental variable incorporated in the error term. The results, based on the raw efficiency scores were as follows:

- *ActewAGL move from being 58% from the frontier firm to 40% from the frontier firm; when adjusted for inputs (according to the AER assumptions and process) and relative to the upper quartile ActewAGL would have received an opex reduction of 12% using this error term method…*

Given that there appears to be no definitive answer over which assumption is the "correct" one for accounting for environmental variables we believe the AER should recognise the significant variations in efficiency scores that can occur with the use of economic benchmarking and should place less reliance on the models for determining specific opex adjustments which are based on volatile estimates of efficiency.

The analysis of Mr Blair highlights the sensitivity of the econometric model to a relatively minor change in its specification and reinforces that the results of the Economic Insights econometric model cannot be relied upon.

<u>Adjustments are arbitrary</u>

Notwithstanding that the adjustments should have been applied before modelling, the AER's after modelling adjustment to compensate for the lack of explanatory power of the econometric model is arbitrary and unsubstantiated. The AER has applied an adjustment to ActewAGL Distribution's CD SFA initial value of 30 per cent, $8.6 million, to account for operating factors not taken into account in the econometric model. The factors contributing to the adjustment implemented by the AER are shown in the table below.

Table 3.7 Adjustments to SFA determined operating expenditure

Environmental factor	% Adjustment	Impact on base year ($million)
Capitalisation policy	17.6%	5.0

[283] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, page 41

Standard control services connections	4.5%	1.3
Backyard reticulation	2.8%	0.8
Taxes and Levies	2.3%	0.7
OH&S regulations	0.5%	0.1
15 combined factors[284]	2.3%	0.7
Total	**30%**	**8.6**

The AER has investigated individually capitalisation policy, standard control services connections, backyard reticulation, taxes and levies and occupational health and safety regulations. The total impact of these adjustments is 27.7 per cent of the total 30 per cent adjustment. The AER has then identified a further 15 factors which it considers to be immaterial and states that:[285]

> *Although individually the effects of these operating environment factors on opex may not be material, their combined effect may be*

In response, the AER has applied a further arbitrary 2.3 per cent adjustment to bring the total adjustment to 30 per cent, or $8.6 million. The application of the 2.3 per cent adjustment to account for the impact of 15 unique factors to round the total adjustment to 30 per cent again highlights the arbitrary nature of the AER's approach and calls into question the need to undertake such a complex econometric process if the final results are applied so arbitrarily.

In addition, the approach adopted to calculating the initial five adjustments is unclear. For example, ActewAGL Distribution submitted that backyard reticulation costs an additional $2.0 million, the AER raised no issues with this cost estimate yet the AER has applied an adjustment of only $0.8 million. ActewAGL Distribution also considers that the adjustment for capitalisation understates the different allocation of costs and only incorporates half of the effect from the new CAM and that ActewAGL Distribution does not capitalise vehicles and computers as discussed previously. Additionally, the AER does not make any adjustments for the significant

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[284] Building regulations, bushfires, corrosive environments, environmental regulations, grounding conditions, natural disasters, planning regulations, proportion of 11kv and 22kv lines, proportion of hardwood poles, service lines, shape factors, skills required by difference service providers, sub transmission, topography and traffic management.

[285] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-91

non-recurring cost items that ActewAGL Distribution incurred in its base year 2012/13, also as discussed previously.

As such, the AER's after modelling attempt to compensate for the inadequacies of the econometric model are arbitrary and cannot be substantiated.

Moreover, in an information request response to the AER on 3 October 2014, ActewAGL Distribution highlighted a selection of its unique cost drivers.[286] Mr Glyde and Mr Mudge have also considered ActewAGL Distribution's unique cost drivers and compared operating environments of ActewAGL Distribution with the frontier businesses identified by the AER. Mr Glyde considers that the AER's benchmarking approach does not fully account for the technical, business practice or unique market factors of ActewAGL Distribution. In addition, Mr Glyde and Mr Mudge identify concerns with the AER's application of the benchmarking outcomes. Mr Glyde Mr Mudge reached the following significant conclusions:[287]

> ***Technical Differences***
>
> *The AER's benchmarking approach does not appropriately account for the technical differences between AAD and the frontier businesses. ...In particular Advisian has identified issues with the AER's benchmarking relating to:*
>
> *(a) Comparability of the DNSPs used for benchmarking purposes;*
>
> *(b) The inadequacy of the AER's benchmarking model to appropriately capture the variability in opex drivers between Australian DNSPs;*
>
> *(c) The failure to appropriately consider the effect of spatial density (customers/km2) in addition to linear density (customers/km) on efficient Opex;*
>
> *(d) The need for DNSPs to operate and maintain the assets they actually have, rather than the assets they might have had (if they had been subject to the same operating environment and historical development as the notional frontier DNSP), in a safe and reliable manner;*

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[286] Including backyard reticulation, economies of scale, proportion of natural hardwood poles in service, customer requirements and expectations, ActewAGL Distribution's high proportion of 132kv assets, the capacity intensity of the network and regulatory obligations such as feed-in tariffs, energy industry levy and the utilities network facilities tax. See also: ActewAGL, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period*, *Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), page 243 and ActewAGL Distribution, 2014, *Response to the AER's Draft Annual Benchmarking Report,* August, pages 3, 6 and 11

[287] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, pages 1 to 5

(e) Differences in reliability and safety performance over the analysis period; and,

(f) The application of the AER's adjustment for additional costs relating to backyard reticulation in the ACT.

Business Practices

The AER's benchmarking approach does not appropriately correct for the differences in business practices between AAD and the frontier businesses. … In particular Advisian has identified issues with the AER's benchmarking relating to:

(a) The AER's reliance on an erroneous and inconsistent assessment of vegetation management expenditure to support its conclusion that AAD is inefficient;

(b) The AER's reliance on an incomplete category analysis (considering only circuit km, and not corrected for reporting differences) to infer that AAD's maintenance expenditure on line and substation assets is inefficient;

(c) The failure to appropriately correct for differences in cost allocation practices, including inconsistencies in the calculation and application of the AER's own ex-post model adjustments;

(d) The failure to appropriately correct the frontier businesses as well as AAD for differences in the allocation of corporate overheads in relation to the Victorian AMI Program;

(e) The failure to appropriately correct the frontier businesses to account for the realisation of specific operational synergies (i.e. shared management and shared control rooms) that are not transparently available to AAD due to its geographical isolation from other DNSPs.

Factors Affecting the ACT

The AER's benchmarking approach does not appropriately take into account the unique market factors that affect the ACT. … In particular Advisian has identified issues with the AER's assessment relating to:

(a) The failure to consider whether benchmarking against the outsourcing approaches adopted by other businesses is achievable in the context of the existing ACT contractor market;

(b) The failure to consider the extent to which AAD's relative isolation limits its ability to realise greater labour and equipment utilisation due through the provision of unregulated contestable services.

AER's Application of Benchmarking Findings

The application of the AER's benchmarking approach is inconsistent with productivity trends over the analysis period and the findings of other independent analysis of the data sets used for benchmarking. … In particular Advisian has identified issues with the AER's assessment relating to:

(a) The inadequate consideration of AAD circumstances, and apparent inconsistency of the AER's interpretation of the revised NER's when compared to the AEMC guidance;

(b) The failure of the methodology used to 'roll forward' productivity scores to account for the significant decline in the assessed productivity of the frontier businesses over the analysis period;

(c) The inability of the SFA CD model and resulting opex cost function to take account of differences in reliability and safety 10 performance between DNSPs resulting in an inconsistency between the reduced opex allowance and the NER requirements and STPIS incentives to maintain reliability at current levels.

(d) The clear contradictory evidence from the Ontario Government's advisory panel with regard to Economic Insights conclusion that statistically, there are no apparent scale economies for DNSPs in the combined Ontario, Australian and New Zealand data set.

Based on his assessment, Mr Glyde and Mr Mudge concludes that: [288]

In our opinion, the AER's alternative forecast is insufficient for AAD to achieve the operating expenditure objectives over the 2014/15 to 2018/19 period as the underlying benchmarking approaches do not adequately take into account:

- *the technical differences between DNSPs;*
- *the differences in cost categorisation between DNSPs;*
- *the actual productivity achieved by the 'frontier' businesses in the base year; and,*
- *the circumstances that are unique to the ACT electricity distribution network.*

As the impact of these factors are not reflected in the AER's alternative Opex forecast, the alternative forecast does not reflect the efficient costs of achieving the operating expenditure objectives for the ACT network.

In response, Mr Glyde and Mr Mudge recommend a series of material adjustments to ActewAGL Distribution's base year operating expenditure to account for technical characteristics, business practices, unique market factors and the AER's application of benchmarking outcomes that are

[288] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 6

not accounted for adequately in the AER's model. Notwithstanding the previous points regarding that adjustments should be undertaken before modelling, in order to ensure comparability with the AER's approach, Mr Glyde and Mr Mudge have identified adjustments to apply to the AER's base year as calculated using its econometric model as shown in the table below:[289]

Table 3.8 Mr Glyde and Mr Mudge's recommended adjustments

Issue	Adjustment $m (% of efficient base)
Advisian Calculated Base Opex[290]	**$30.93** (100.0%)
Issues Identified by the AER in the draft decision	
AER Jurisdictional Taxes	**+$0.71m** (2.3%)
AER Standard Control Services Connections	**+$1.40m** (4.5%)
AER OH&S	**+$0.15m** (0.5%)
AER Miscellaneous Factors	**+$0.74m** (2.4%)
Backyard Reticulation[291]	**+$2.00m** (6.5%)
Technical Factors	
SWER Circuit Length	**+$0.38m** (1.2%)
Linear v Spatial Density	Adjustment to model **or** As revealed in the audited base year
Installed Transformer Capacity v Ratcheted Maximum Demand	Adjustment to model **or** As revealed in the audited base year
Reliability	**+$1.26m** (4.1%)
Backyard Reticulation	**+$2.0m** (6.5%)

[289] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, pages 7 to 8

[290] Advisian notes that this differs from the 'base' opex determined from the Economic Insights model. This is because the Economic Insights model determines base opex for the midpoint of the analysis period and then 'rolls forward' the figure to account escalation to a 2012/13 base and to allow for growth in the factors taken into account in the opex cost function determined from the SFA CD results. Advisian's calculation is based on the AER's spreadsheets used for AAD's draft decision, an electronic copy of the spreadsheet has been provided to AAD.

[291] Inclusive of the component included in the AER's draft decision

Issue	Adjustment $m (% of efficient base)
Business Practices	
Vegetation Management	Review the basis for rejection of AAD's revealed costs
Maintenance	Review the basis for rejection of AAD's revealed costs
Operating Leases[292]	**+$3.00m** (9.7%)
'Capitalisation Policy'[293]	**+$9.90m** (32.0%)
Pole Top Structures	**+$3.32m** (10.7%)
Network 'Overheads'	**+$4.64m** (15.0%)
AMI Corporate OH Allocation	**+$0.85m** (2.8%)
Realised Synergies CitiPower/Powercor Corp OH	**+$1.08m** (3.5%)
Realised Synergies Victorian Network Operations	**+$0.80m** (2.6%)
AER Application Factors	
2013 Basis Productivity Scores	**-$0.18m** (0.6%)
Remove Potential for Double Counting	
Less AER 'Capitalisation Policy' and 'Miscellaneous' adjustment	**-$10.64m** (34.4%)
Total (Sum)	**$50.36m** (62.8%)
Cumulative effect	**+$15.06m** (48.7%)
Total (Cumulative)	**$65.42m** (111.5%)

Mr Glyde and Mr Mudge after compensating for the factors omitted from the AER and Economic Insights analysis estimates an opex allowance comparable with ActewAGL Distribution's revealed cost opex.

In conclusion, the AER has failed to apply the necessary before modelling adjustments to the data set and has therefore been forced to adopt a model that does not capture the required environmental variables. In order to compensate, it has incorrectly applied after modelling

292 Inclusive of the component included in the AER's draft decision

293 Inclusive of the component included in the AER's draft decision

adjustments which are arbitrary and unsubstantiated. In addition, the adjustments significantly. under compensate for the actual characteristics of ActewAGL Distribution's network.

The AER's efficiency frontier adjustment from 2009 to 2013 has been applied incorrectly

The AER has made a further adjustment to the efficiency frontier in an attempt to recognise that the data set is based on the mid-point of 2006 and 2013 data (i.e. the mid-point of 2009) and as such must be translated into current terms. As part of this adjustment, the AER has applied a $4.9 million increase to ActewAGL Distribution's CA SFA initial value.

However, Mr Blair has identified an 'error inherent in the calculation of the frontier'.[294] The AER has failed to recognise that the frontier itself has moved since 2009 with the productivity of the frontier businesses falling 9 per cent. The error in calculating the frontier has resulted in ActewAGL Distribution, using the AER's modelling approach, appearing 9 per cent less efficient than is actually the case.[295] As such, adopting the AER's approach, a greater increase to the initial CD SFA value is required.

This point is also identified by Mr Glyde and Mr Mudge identify an issue in:[296]

> *the AER's application of the Opex benchmarking results …[in] the use of the average productivity score over the analysis period (2006-2013) rather than using the actual score of the frontier businesses in 2013. This places a significant upward bias in the productivity scores for the South Australian and Victorian DNSPs whose assessed productivity have declined considerably over the period*

The efficiency frontier is established incorrectly

Economic Insights and the AER has acknowledged the model limitations, data imperfections and other uncertainties inherent in the econometric modelling. Economic Insights notes:[297]

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[294] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, page 53

[295] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, pages 53 to 55

[296] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 104

[297] Economic Insights, 2014, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November, page 28

*We first examined the scope to estimate an opex cost function using only the AER's economic benchmarking RIN data on 13 DNSPs over an 8 year period (104 observations in total). However, this produced **econometric estimates that were relatively unstable**. … We observed that small changes in variable sets (and methods and functional forms) could have a substantial effect on the output elasticity estimates obtained and the subsequent efficiency measures derived from these models. … **After a careful analysis of the economic benchmarking RIN data we concluded that there was insufficient variation in the data set to allow us to reliably estimate even a simple version of an opex cost function model (emphasis added)***

In addition, Economic Insights states:[298]

all models are by definition a simplification of reality and may not capture all relevant effects

In addition to their attempt to address these concerns via the incorrect application of adjustments discussed above, they have also applied a further adjustment to the efficiency frontier against which ActewAGL Distribution is assessed. The AER has compared ActewAGL Distribution against a hybrid efficient business by creating a weighted average of all networks with an efficiency score above 75 per cent. This has the result of increasing the base year opex for ActewAGL Distribution's CD SFA initial value by $2.7 million.

ActewAGL Distribution submits that this is flawed for three reasons:

- Given the concerns already identified with the AER's approach and the AER's claim that a cautious approach is necessary, the adoption of average performance is more appropriate than adopting an estimate of the frontier;
- Businesses should be grouped into 'like-with-like' groups, or latent classes; and
- The frontier 'hybrid' efficient company is not representative.

To begin with the need to make such an adjustment to the frontier highlights that the model is a gross simplification of reality and is unable to capture all relevant factors of the model. Professor Newbery notes that:

It is worth noting that when regulatory judgement is applied to the frontier after it is estimated via SFA it calls into question why this more complex and less transparent technique was chosen in the first place. [299]

[298] Economic Insights, 2014, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November, page 47

[299] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 38

Use of average performance rather than frontier firms

Notwithstanding the concerns of Professor Newbery ActewAGL Distribution does not consider the approach of the AER to be sufficiently cautious.

Rather, ActewAGL Distribution submits that the adoption of an average performance is more appropriate than the use of a frontier. By estimating an efficiency frontier, Economic Insights are producing an estimate of the short-run, *unsustainable* cost function which is inconsistent with the NEO and the long term interests of consumers.

An analysis of econometric benchmarking of United States power companies by Dr Lowry and Dr Getachew identifies the need to take a longer term perspective of efficiency (and by implication include dynamic and allocative efficiency as well as purely productive efficiency as is the case for frontier modelling). Dr Lowry and Dr Getachew find that estimating a frontier is inherently biased and that an average approach is preferred:[300]

> *Existing frontier benchmarking methods estimate the distance from the unsustainable cost frontier and are therefore inherently biased in measurement of the distance from the more relevant long run sustainable frontier. This problem is not encountered with an average industry standard.*
>
> *…there is currently no effective way to identify the sustainable minimum cost of utility service. At each point in time several utilities in a sample used for benchmarking will likely incur costs that are below the sustainable minimum.*

The AER uses frontier benchmarking to determine the costs of a hypothetical 'efficient' firm, and has used the costs of this hypothetical 'efficient' firm to set actual expenditures for ActewAGL Distribution. Dr Lowry and Dr Getachew argue this is incorrect and that the average performance is a more suitable benchmark:[301]

> *…benchmarking methods are either based on best or frontier performance or on representative or average performance.*
>
> *… We posit that average performance most clearly embodies a competitive market standard and the best performance embodies a frontier standard.*

[300] See Attachment C33, Lowry, M.N., Getachew, L. and Hovde, D., 2005, *Econometric Benchmarking of Cost Performance: The Case of U.S. Power Distributors*, The Energy Journal, vol. 26, no. 3, page 77

[301] See Attachment C34, Lowry, M.N. and Getachew, L., 2009, *Statistical benchmarking in utility regulation: Role, standards and methods*, Energy Policy, vol. 37, page 1326

…superior cost performers in competitive industries are entitled to superior returns. If firms must operate on the frontier to earn a competitive return, the regulator is essentially acting as a monopsonist on behalf of customers.

A similar point was also identified by the AER and ACCC Regulatory Development Branch which identified the need to appropriately incentivise businesses and allow for dynamic efficiencies: [302]

As suggested by the Productivity Commission (2012, p. 141), the objective of a regulatory regime should be to incentivise benchmarked businesses to operate close to, but not necessarily on, the frontier. This approach provides for an incentive gap to reward businesses for being dynamically efficient. This approach also addresses potential regulatory error. The implication is that caution should be exercised in relation to the use of raw results from frontier-based methods.

In addition to this conceptual issue, the practical issue of sensitivity of frontier methods is not considered by the AER. Dr Lawrence, one of the authors of the Economic Insights report on which the AER based its operating expenditure decision, has previously stated the limitations with using frontier approaches to benchmark firms:[303]

The average approach does appear to replicate the market outcome more closely but runs the risk of too low a target being set. On the other hand, frontier approaches (including stochastic frontier analysis) are ***more sensitive to data errors and can lead to unrealistically high and, indeed unachievable, targets being set.(emphasis added)***

Taking on board the issues outlined by Dr Lawrence,[304] the New Zealand Commerce Commission implemented benchmarking relative to an average performing firm, rather than a frontier performing firm:[305]

Given the sensitivity of a frontier approach to outliers in the presence of poor data quality, the Commission considers that it is prudent to reset the price path threshold for the regulatory period beginning in 2004 on the basis of average rather than frontier performance.

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[302] See Attachment C18, ACCC/AER Regulatory Development Branch, 2013, *Economic Benchmarking Model: Technical Report,* page 20

[303] See Attachment C35, Meyrick and Associates, 2003, *Regulation of Electricity Lines Businesses Resetting the Price Path Threshold – Comparative Option*, September, page 43

[304] See Attachment C35, Meyrick and Associates, 2003, *Regulation of Electricity Lines Businesses Resetting the Price Path Threshold – Comparative Option*, September

[305] See Attachment C36, Commerce Commission, 2004, *Regulation of Electricity Lines Businesses, Targeted Control Regime, Threshold Decision (Regulatory Period Beginning 2004)*, April, page 40

Economic Insights' report to the AER mentions briefly but does not consider in detail the use of an average cost function (i.e. average performance) before adopting a minimum cost function (i.e. frontier performance) as the benchmark.[306] The difference has been considered by NERA Economic Consulting:

> *The subtle but important distinctions between perfect and real world efficiency, and the perfect and effectively competitive market thresholds that are consistent with these concepts, give rise to the question as to whether the benchmark concept for an 'efficient' firm applied by regulators should be one of 'average' efficiency or 'perfect' efficiency. Each business is an amalgamation of different operations. Some firms will simply be better at some of these operations than others. It would be unrealistic to expect any one firm to be able to attain frontier efficiency across all of its operations. It follows that setting expenditure benchmarks by reference to 'perfect' efficiency runs the risk of establishing tariffs that are below the lowest sustainable cost of delivering the service that is practically achievable for all firms. Tariffs set by reference to 'perfectly efficient' costs risk undermining service providers' incentives to undertake efficient investment and may therefore be detrimental to dynamic efficiency and so to the long-term interests of consumers.*
>
> *Related aspects of the regulatory regime applying to DNSPs also throw light on the appropriate interpretation of 'efficient costs'. The NEL requires the service provider to be provided with the opportunity to earn 'more than' its efficient costs (Section 7A(2)). This implies that efficient costs are not to be interpreted as 'perfectly efficient' costs which, by definition, cannot be bettered … The NEL also requires the service provider to be given effective incentives, which forms the basis for the efficiency benefit sharing scheme set out in the NER.*
>
> *If every firm could attain 'perfect' efficiency on an ongoing basis, then there would be no need for either of these provisions, which have the primary purpose of incentivising improved efficiency performance. Notwithstanding that, in practice, perfectly competitive markets and perfectly efficient firms amount to an unattainable threshold and so represent an unrealistic benchmark against which to assess regulated firms' expenditure, the regulatory regime seeks to ensure that profit maximising firms are always striving to improve their efficiency. Adopting a benchmark of 'average' efficiency in assessing expenditure does not therefore mean that a regulated firm's incentives to improve its efficiency are in any way diminished.* [307]

Shuttleworth has also considered the implications of average and perfect efficiency noting that:

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[306] Economic Insights, 2014, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November, page 8

[307] See Attachment B1, NERA, 2014, *Economic Interpretation of Clauses 6.5.6 and 6.5.7 of the National Electricity Rules Supplementary Report for Ausgrid*, pages 8 to 9.

> *The main aim of benchmarking is to identify ''efficient costs''... In other industries, efficient companies earn a reward for their exceptional performance, in the form or higher than average returns… the CAPM method of setting the allowed rate of return … focuses on average stock market performance…. therefore [the regulator offers] average returns for exceptional performance –a combination that potential investors will find unattractive compared with the returns on offer in other industries. Regulated companies operating under this kind of regime would therefore find it difficult or impossible to attract or retain capital for investment.*[308]

While the AER considers its approach of producing a hybrid efficient firm based on those that score above 75 per cent, when considered against international experience it is not the case.

Professor Newbery notes that the use of an upper quartile approach has been adopted by Ofgem and Ofwat he points out that this approach is only adopted once the regulator has collected data on a transparent and consistent basis over a long period; having tried and tested models result in higher confidence in the data and reduce the need for making further discretionary adjustments.[309] He also notes that instances of where Ofgem have benchmarked operating costs at the upper third due to data variability.[310]

The approach of Ofgem and Ofwat implies that the AER and Economic Insights should take a more cautious approach than that which it has adopted given the numerous issues identified with their approach. Professor Newbery, in considering evidence from international regulators, has noted that:

> *In relation to 'aiming-off' the frontier (or choosing a less challenging frontier), regulators have shown a large degree of discretion in determining the extent to which inefficient companies need to close the gap to the frontier and how quickly they need to do this. This is even after the regulator has used its discretion in choosing a frontier. In making their judgement regulators take into account:*
>
> - *the robustness of the data and maturity of the dataset;*
> - *the modelling technique used;*
> - *the choice of the 'frontier'; and*

308 See Attachment C30, Shuttleworth, G., 2005, Benchmarking of electricity networks: Practical problems with its use for regulation, vol.13, September, page 317

309 See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 42, table 4.1

310 See Attachment C37, Ofgem, 2009, *Electricity Distribution Price Control Review: Final Proposals*, December, page 40

- *the feasibility of the company cutting its costs, while maintaining financeability, reliability and safety.*

> *In almost all cases they have taken a more cautious approach than using a simple frontier in order to recognise the limitations of the modelling and the economic costs and risks placed on the companies. This is not dissimilar to the revenue and pricing principles that the AER must take into account as set out in Section 7A of the NEL.* [311]

Moreover, the approach of averaging the results of firms that achieve an efficiency score of at least 75 per cent is specific to the current set of results derived from the model. It is possible to envisage a scenario where all firms achieved an efficiency score of over 75 per cent. In this instance, the AER's approach to establishing the frontier would not work, Professor Newbery considered that:

> *if a different specification was run and all companies achieved efficiency score of over 75% then the AER's approach would not work in the way intended, in my opinion, as the frontier would be an average over all the DNSPs' efficiency scores.* [312]

Given that the use of a frontier business represents an unsustainable cost function and that perfect efficiency is not realistically attainable, ActewAGL Distribution does not consider the use of hybrid efficient company based on those with efficiency scores above 75 per cent to be a cautious approach.

Grouping of business into latent classes would be more reasonable

There are significant differences between the DNSPs included in the econometric model data set. A well-recognised approach to dealing with differences between businesses is to group businesses into latent classes, i.e. like-with-like groups such as grouping rural and urban businesses separately. Once the groups have been established, specific frontiers are established for each group against which its efficiency is judged. Such an approach is especially valid within the context of the AER adopting a single environmental variable (proportion of underground cabling) as discussed earlier.

Mr Glyde and Mr Mudge, following their analysis of Australian DNSPs and comparison with the international data set, notes that they:[313]

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[311] See Attachment C3, CEPA, 2015, *Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 50

[312] Attachment C3, CEPA, 2015, *Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page vi

> *would have expected the benchmarking analysis to include some 'class' analysis that maximised homogeneity within the classes, and maximised heterogeneity between classes.*

However, despite the differences in the underlying composition of the data set, Economic Insights has failed to adopt such an approach despite previously recognising the importance of grouping like-with-like businesses to take into account differences in the inputs and outputs of individual businesses:[314]

> *Economic Insights (2009a) demonstrated that while technical change may be relatively common across DBs, differences between prices and underlying costs on both the output and input side mean that achievable TFP growth is likely to vary significantly across DBs. This means that it is likely to be necessary to divide DBs into at least a small number of peer groups.*

It is difficult to reconcile Economic Insights' advocating the use of latent classes in measuring changes in productivity in 2009, but not considering it an issue with an expanded, international data set, in 2014.

Mr Blair finds that a single frontier in the Australian environment is unlikely and undertook latent class modelling and identified four different classes. The failure by Economic Insights to consider the use of latent classes in its establishment of the efficiency frontier results in overestimation of the inefficiency of DNSPs who are not benchmarked against comparable businesses.[315]

<u>Concerns with development of the theoretical frontier efficient firm</u>

The theoretical efficient business developed by Economic Insights against which ActewAGL Distribution is considered is based on those businesses with an efficiency score above 75 per cent. Economic Insights developed the theoretical firm based on a weighted average of five businesses. However, the theoretical firm is not representative of a typical Australian DNSP and differs substantially from ActewAGL Distribution.

Mr Glyde and Mr Mudge identify that the hybrid company generally maintains smaller volumes of assets per customer than the industry average across both line and substation assets.

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[313] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 35

[314] See Attachment C38, Economic Insights, 2009, *Total Factor Productivity Index Specification Issues,* December, page 36

[315] See Attachment C4, Huegin, 2015, *Huegin's response to Draft Determination on behalf of NNSW and ActewAGL, Technical response to the application of benchmarking by the AER*, January, pages 55 to 56

Similarly, in comparison with the frontier company, ActewAGL Distribution operates and maintains: [316]

- *significantly less line assets per customer than the frontier business;*
- *significantly more zone and distribution substation assets per customer than the frontier business; and,*
- *significantly more underground network than the frontier business.*

As the AER's network scale metrics relate to line length and not installed substation capacity, the higher zone and distribution transformer capacity per customer represents a significant additional opex requirement that is not accounted for in the AER's model specification.

Specifically, Mr Glyde and Mr Mudge identifies, in comparison with the Victorian urban DNSPs, that ActewAGL Distribution must operate and maintain:[317]

- *36% more sub transmission lines;*
- *40% more zone substation transformer capacity;*
- *108% more 11kV-33kV distribution lines;*
- *32% more distribution transformer capacity; and,*
- *38% more low voltage line.*
- *41% more poles per customer;*
- *20% more route length per customer for an equivalent circuit length;*
- *36% more overhead line length per customer.*

Mr Glyde and Mr Mudge concludes that: [318]

This fundamentally disadvantages AAD

In conclusion, the AER has not adopted a cautious approach, especially within the context of the numerous issues with its approach and the use of average performance against which to

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[316] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 46

[317] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, pages 47 and 48

[318] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 47

consider DNSPs performance is more appropriate than a frontier. The AER has also failed to recognise the importance of grouping businesses into like-with-like groups. In addition, the hybrid efficient company is not representative of the industry and ActewAGL Distribution.

3.4.4.6 *Alternative benchmarking models would lead to different conclusions*

Professor Newbery has developed alternative benchmarking models using only Australian RIN data.[319] Professor Newbery did not use the international data provided by the AER due to his significant concerns about the robustness of inefficiency estimates that may be produced using these data sets.[320]

The models developed by Professor Newbery overcome a number of deficiencies, albeit not all, identified with the AER's model, including:

- Greater normalisation of the RIN data
- Incorporation of a greater range of operating environment variables
- Assessment of a greater range of parametric techniques.

Accordingly, Professor Newbery was able to produce superior results using corrected ordinary least least squares (COLS) and random effects (RE) econometric models, shown against the AER's preferred model below in Figure 3.5 and Figure 3.6. These econometric concepts are explained further in Attachment C3.

[319] Problems with using international data are discussed in section 3.4.4.5.

[320] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 18

Figure 3.5 CEPA OLS efficiency Scores versus AER preferred model[321]

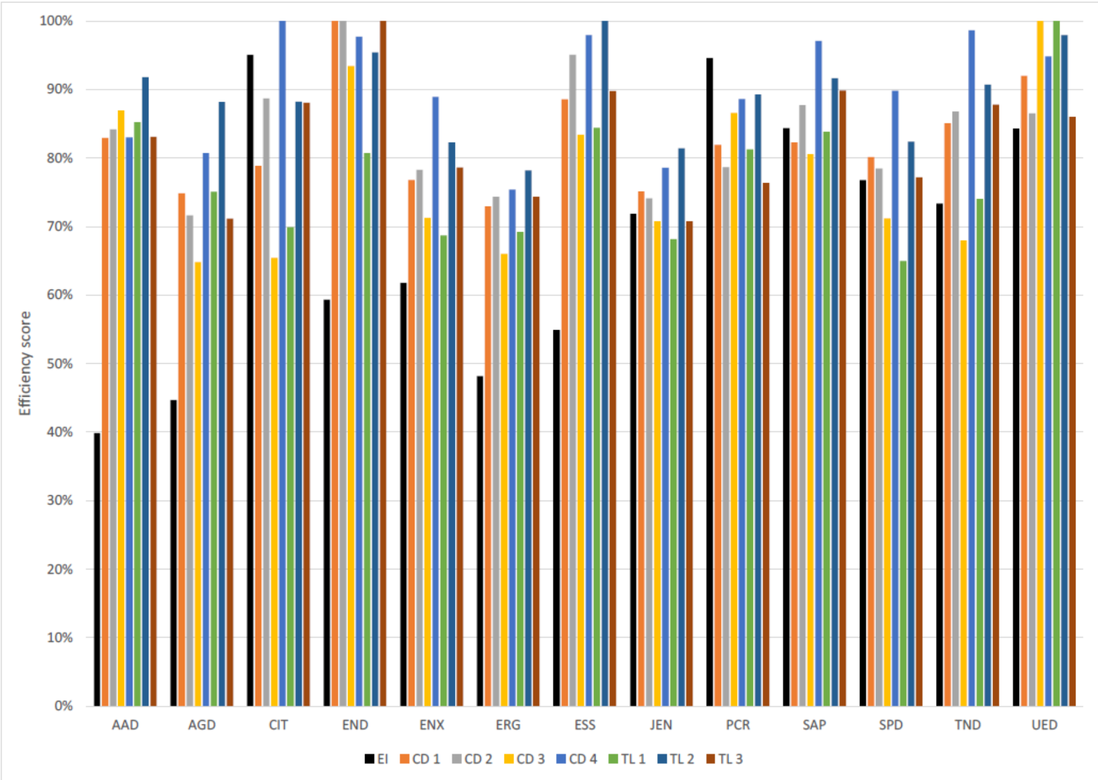

Figure 3.5 shows Economic Insights SFA results (black) against 7 of Professor Newbery's OLS alternative models which comprise of 4 Cobb-Douglass and 3 Translog model results. The range of scores is significantly tighter than those estimated by Economic Insights with the lowest efficiency score above 60 per cent.[322] As with the OLS models Professor Newbery's alternative RE (GLS) models produce a tighter range of efficiency scores than Economic Insight's results, as shown in Figure 3.6. The lowest efficiency score in the case is slightly over 50 per cent.

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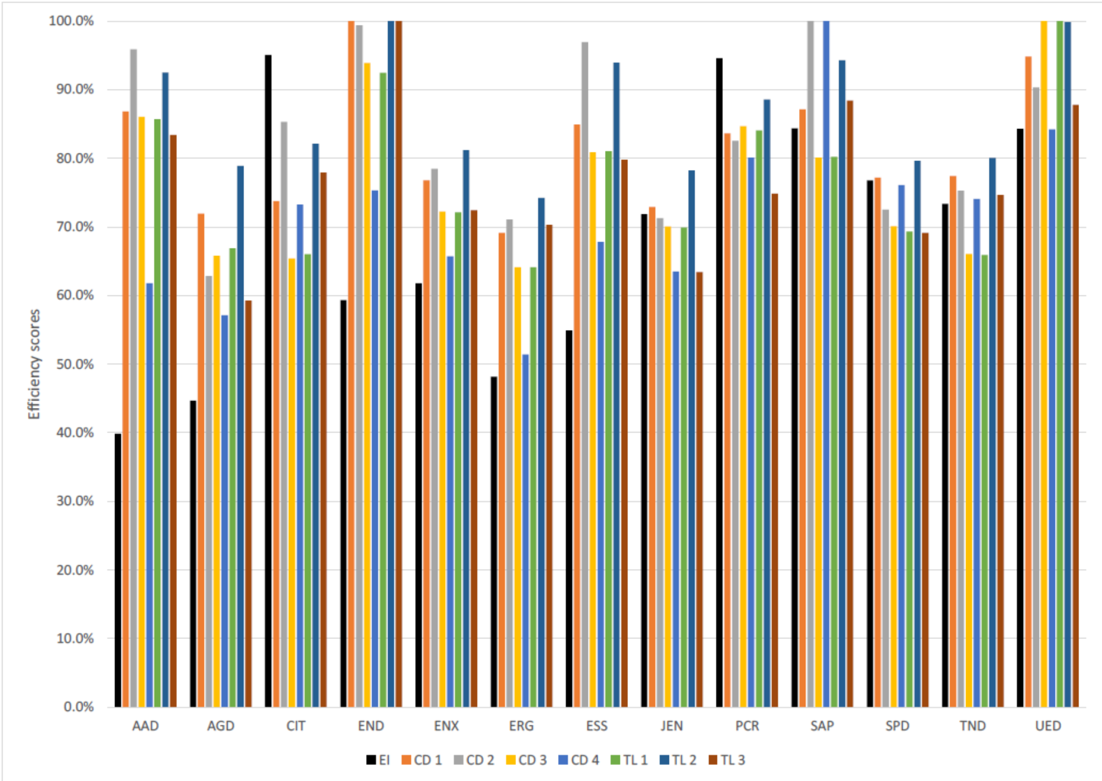
[321] Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 27

[322] Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 28

Figure 3.6 CEPA RE (GLS) efficiency scores versus AER preferred model[323]



Professor Newbery's results are in stark contrast to the Economic Insight's consistent results which gave the AER:

> *…confidence that the models provide an accurate indication of the efficiency of base year opex.*[324]

ActewAGL Distribution considers this confidence misplaced.

Using the results of the alternate models, Professor Newbery examines the impact of both sets of efficiency scores on the implied opex allowance for ActewAGL Distribution. In doing this, Professor Newbery uses three frontier definitions:

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[323] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 31

[324] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-60

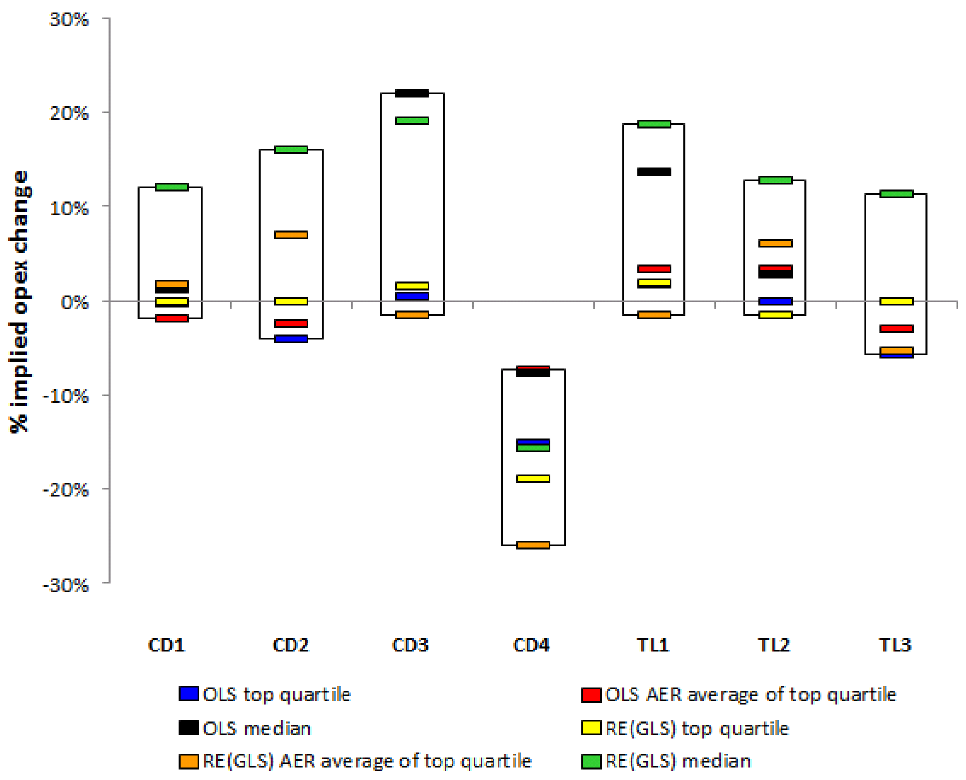
- the AER's approach of averaging the efficiency over companies that achieve an efficiency score of at least 75 per cent;
- the upper quartile itself; and
- the median efficiency score.[325]

The horizontal axis in

Figure 3.7 represents the frontier under each definition used by Professor Newbury. Model results for ActewAGL Distribution above the axis imply an increase in the base year opex, whereas results below the axis imply a base year opex reduction.

[325] See Table 3.5 and 3.8 of Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 28 and 32

Figure 3.7 Implied opex change for ActewAGL Distribution using Professor Newbery's alternative models[326]



If the results of these alternative models were to be applied mechanistically like the AER's approach, the implied opex adjustments would result—for 6 out of 7 models—in ActewAGL Distribution's base year opex to be set at similar levels as those in ActewAGL Distriubtion's regulatory proposal. Moreover, for many of the model/frontier combinations, used mechanistically, would result in an increase in the base year opex.

All specifications aside from CD 4 include 132kV share of circuit as an environmental variable. Therefore Professor Newbery noted that including this variable significantly reduces the range of efficiency scores across the companies and that:

[326] ActewAGL Distribution analyais based on table 3.5 and 3.8 of Attachment C3, CEPA, 2015, *Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 28 and 32

…as this variable is significant, and positive, in almost all the specifications I tested it does indicate that operating higher voltage lines and cables requires higher opex than lower voltage lines... [327]

While it may be argued that the 'share of 132kV circuit' may be capturing other differences between the NSW, ACT and QLD networks and those of the other states, its general 'significance' and the significance of RAB additions in specifications without share of 123kV indicates that there are operating differences that the Economic Insights' model was not picking up.[328]

This result is consistent with Mr Glyde's and Mr Mudge's observation that there are differences in scope and legacy design across jurisdictions:

Whilst not directly an issue for AAD (other than through model misspecification), Advisian has previously identified a major issue in NSW and Queensland relating to scope of activities and legacy design issues which results in a significant expansion of transformer capacity in those states on a relative basis. The issue arises from NSW and Queensland DNSPs taking bulk supply at 132kV or 110kV, and then transforming it to a 33kV sub-transmission voltage before a final transformation to high voltage distribution level. This issue arose as new networks were interfaced to legacy networks. As a general principle the Victorian and South Australian DNSPs that form the 'frontier DNSP' transform from 66kV to their relevant high voltage (22 or 11kV). In comparison, AAD transforms its energy from 132kV supply from TransGrid directly to 11kV.[329]

Therefore it can be inferred that the CD4 model is less robust than the other alternate models, as it fails to include necessary environmental variables.

Professor Newbery finds that significant caution should be placed on the results of any one specification as it is unlikely to control for all differences and that a greater range of operating variables and models are almost certainly required to control for the differences between DNSPs.[330] Professor Newbery concludes:

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[327] See Attachment C3, CEPA, 2015, *Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 34

[328] See Attachment C3, CEPA, 2015, *Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 28

[329] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, pages 52

[330] See Attachment C3, CEPA, 2015, *Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page v

> *Even normalising for differences identified by Economic Insights/ AER prior to modelling leads to a different efficiency target for the DNSPs. Given these issues, the AER's reliance on the econometric analysis may not be in the long-term interests of consumers, and therefore not promoting the NEO, as the expenditure levels may be set below those required for the safe, secure, reliable operation of the network.*
>
> *I have not tried to identify a suite of or single perfect model for opex benchmarking, this is a much more exhaustive process than the time allows. Rather, my analysis shows that there are operating environment differences that Economic Insights have not controlled for in its modelling. The modelling I have done provides a much tighter range of efficiency scores than those produced by Economic Insights' preferred model.* [331]

The large variation in results produced by Professor Newbery shows clearly that the selection by the AER of *one* model on which to base its base year opex decision is incorrect or unreasonable in all the circumstances. ActewAGL Distribution contends that the AER cannot have confidence in the results produced by the Economic Insights models and should instead revert to relying on the revealed cost approach.

In summary, the alternative models developed by Professor Newbery are superior to those developed by Economic Insights as they undertake greater normalisation of the data and more accurately take into account ActewAGL Distribution's operating environment. The results from these alternative models indicate that there is a much tighter range of efficiency scores. The impact on ActewAGL Distribution's base year opex allowance range from lower opex reductions, and for some models, higher implied base year opex. These outcomes:

- highlight the inconsistency in results generated by different benchmarking models and identify the risk of placing reliance on a single model as done by the AER; and
- affirm that the only correct and reasonable use of benchmarking is as an informative tool to identify areas for further investigation, and that it is incorrect and unreasonable to accord the weight to benchmarking that the AER accords it in its draft decision.

3.4.4.7 *The AER's supporting PPI analysis fails to substantiate benchmarking analysis*

One of the techniques that the AER has used to compare the performance of different DNSPs is the Partial Performance Indicator (PPI) analysis. The PPI analysis connects the quantity of an

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[331] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page vi

input (e.g., opex) with the quantity of a single output produced by the business (e.g., customer numbers).[332] The AER has examined two PPIs:

1. total customer cost (opex, return on capital and depreciation costs) per customer; and
2. total opex per customer.

The AER then compares the level of these PPIs for ActewAGL Distribution with those of Powercor, the DNSP that the AER considers to be a 'top performer'. The comparison shows that ActewAGL Distribution's total customer cost per customer and opex per customer is higher than that of Powercor. According to the AER, these results corroborate the findings of its economic benchmarking analysis.[333]

ActewAGL Distribution acknowledges that PPIs may assist in identifying areas that warrant further investigation. Indeed, this is consistent with the AER's own statements as to the purpose and limitations of the PPI analysis:

> *…PPI-based benchmarking results are best viewed as providing a useful means of comparison and an indication of where certain expenditure may be above efficient levels, but should not be viewed in isolation as a definitive assessment on the efficiency of an energy network business.*[334]

However, the AER has drawn conclusions from the PPI analysis that fail to acknowledge the inherent limitations of this technique. In particular, the AER's claim that the PPI analysis corroborates the findings of the benchmarking analysis presupposes that the technique provides a definitive assessment of the efficiency of a DNSP's expenditure. This is simply incorrect.

In a joint ACCC and AER working paper, the AER has itself acknowledged the limitations on the value of PPIs, and their potential to provide misleading information. [335] There are three principal limitations that this working paper identified:

1. Data quality;
2. One-dimensional nature of PPI benchmarking; and

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[332] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-18

[333] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-18

[334] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 35

[335] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 17 & 32

3. The assumed linear relationship between inputs and outputs.

Each of these limitations is pertinent to the AER's PPI analysis as undertaken in its draft decision.

Data quality

Firstly, PPIs require consistent data collected using like-for-like definitions.[336] As the AER notes "If data are not collected on a consistent basis, then any comparison or benchmarking carried out using the data is likely to be flawed."[337]

Issues such as inconsistent reporting of data and different cost allocation methodologies across DNSPs, discussed in section 3.4.4.5 in the context of the AER's econometric benchmarking method, apply equally to PPI benchmarking. As Professor Newbery notes:

> *Failure to normalise the data may lead to unreliable results, and potentially the choice of inappropriate model specifications. Ofgem, considered to be a leader in benchmarking, spends a considerable amount of time setting out the cost categories, asset lists, and reporting guidelines to ensure that the data is reported on a like-for-like basis regardless of the regulated companies' own internal cost reporting. I note that failure to normalise the data will impact on the category analysis, not just the econometric benchmarking.*[338]

Given that the data are not collected on a consistent basis, any comparison carried out on the basis of the benchmarking is flawed.

One-dimensional nature of the PPIs

The second consideration is that the one-dimensional nature of the PPIs provides a simplistic and so potentially misleading impression of performance.[339]

PPIs consider only one aspect of a business at a time, namely the business's inputs and outputs.[340] In the ACCC and AER joint working paper, the AER states that this inadequate

[336] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 34-35

[337] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 17

[338] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 33

[339] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 18

[340] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 17

accounting of multiple outputs makes performance comparisons across utilities less useful for regulators.[341]

ActewAGL Distribution submits that the AER cannot rely on an analysis that it considers 'less useful for regulators'. It is also concerning that the AER has failed to recognise limitations of the PPI analysis that it has previously identified outside of the determination process.

The AER has recognised that PPIs cannot take into account differences in the operating environment of a DNSP beyond the control of management.[342] The AER raises this issue in the draft decision noting that 'PPIs do not explicitly account for operating environment factors, so we must bear this in mind in interpreting the results'.[343] Notwithstanding these statements, the AER has made no attempt to investigate the effect of operating environment factors on the results or to normalise the data for known operating environment factors, including those factors that AER describes as relevant to ActewAGL Distribution elsewhere in its draft decision.[344]

The failure to account for operating environment factors means that the AER is essentially examining differences in the operating environment of each DNSP rather than any measure of relative costs.

The effect of the failure to account for operating environment variables is exacerbated by the AER's decision to account for scale by normalising all PPIs by a single measure, i.e., customer numbers.[345] The AER's rationale for this decision was that economic benchmarking suggests that customer numbers are the most significant driver of costs.[346] As the AER's has previously noted,

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[341] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 17

[342] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 17

[343] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-62

[344] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-90

[345] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-62

[346] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-62

the adoption of other measures can lead to the identification of different best and worst performers. [347]

The AER's approach stands in stark contrast to that of Economic Insights,[348] the AEMC[349] the ACCC[350] and Mr Glyde and Mr Mudge [351] all of whom state that customer density and energy density are the two main environmental operating factors that affect energy distribution businesses' productivity. In developing alternative economic benchmarking models, Professor Newbery has used model specifications made up of circuit length, a form of customer density, share of underground cables, share of 132kv circuit, share of SWER, and RAB additions and a time trend.[352] None of these cost drivers feature in the AER's analysis.

It is therefore unsurprising that the AER's PPI analysis and econometric benchmarking models provide similar results, because they are both derived from the same cost data and the same cost driver, i.e., customer numbers. The results of applying these two techniques neither corroborate one another nor 'reveal a diverse – but consistent – body of evidence'.[353]

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[347] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 17-18

[348] Economic Insights discuss the importance of customer density and energy density in three reports in respect of gas distribution businesses and note that electricity businesses are similar. See Attachment C39, Economic Insights, 2012, *Econometric Estimate of the Victorian Gas Distribution Businesses' Efficiency and Future Productivity Growth*, March, page 11; Attachment C40, Economic Insights, 2012, *The Total Factor Productivity Performance of Victoria's Gas Distribution Industry*, March, page 14; Attachment C41, Economic Insights, 2009, *Assessment of Data Currently Available to Support TFP-based Network Regulation*, June, page 14; Attachment C42, Economic Insights, 2011, *Regulation of Suppliers of Gas Pipeline Services – Gas Sector Productivity*, February, page 33

[349] See Attachment C43, AEMC, 2008, *Review into the use of Total Factor Productivity for the determination of prices and revenues, Framework and Issues Paper*, December, page 14

[350] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 59

[351] See Attachment C2, Advisian, 2015, *Opex cost drivers ActewAGL Distribution Electricity (ACT),* January, pages 36 to 44

[352] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 30

[353] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-68

The AER's circular reasoning continues with the claim that operating environment factors only explain part of the differential in the total customer cost PPI between ActewAGL Distribution and Powercor.[354] The AER's basis for this conclusion is that the PPI results are similar to the results of the SFA benchmarking model.

In summary, the AER has appealed to the results of the PPI analysis to support the findings of its benchmarking analysis – an analysis that ActewAGL Distribution has demonstrated is not robust. However, the PPI analysis is merely a simpler version of the same analysis, derived from the same data, and largely driven by the same variable, customer numbers.

The AER's analysis, as with all PPI analysis, cannot take into account differences in the quality of the outputs produced. It assumes that all outputs are identical, and that all customers have the same preferences. As the AER notes:

> *In particular, PPIs used in isolation cannot easily take into account differences in the market or operating environment that impact upon a business but are beyond the control of management. For example, a utility may have a relatively high or low unit cost simply because it faces input prices or serves customers that are different from those for utilities operating in other regions. Because of this, they may present problems in providing a meaningful comparison of businesses in different operating environments.*[355]

The AER's assumption that all customers have the same preferences is obviously false. As ActewAGL Distribution notes in Chapter 12, evidence suggests the value placed on reliability by customers in the ACT is different to the value placed on reliability by customers in New South Wales.

Linear relationship between inputs and outputs

The final limitation of PPIs is that they assume a linear relationship between inputs and outputs, and that all changes in the value of an input can be associated with a corresponding change in the output (or vice versa).[356] However, in a great many circumstances the change in the use of an

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[354] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-63

[355] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 17

[356] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 17 & 32

input will depend on a multitude of inputs, outputs and other factors not described by the model.[357]

For example, the AER's decision to normalise only for customer numbers does not contemplate smaller firms having higher 'per customer' costs. The AER's analysis is therefore predicated on a linear relationship. If scale effects are significant, this relationship would fail to hold. International evidence suggests that economies of scale and density are likely to exist.[358]

Conclusion

Notwithstanding the importance of these three limitations, the overarching error that the AER has made is to perform an analysis that so clearly contradicts its own statement, that PPIs:

> *should not be viewed in isolation as a definitive assessment on the efficiency of an energy network business.*[359]

PPIs should be used as a means of comparison and an indication of where certain expenditure may be above efficient levels which should be followed up by a more definitive assessment and cannot be viewed in isolation. The AER did not link its purported detailed reviews of two detailed categories of costs (ActewAGL Distribution provides a response to these reviews in Attachment 11) but instead considered PPIs as a 'crosscheck' to econometric benchmarking findings.[360]

However, using two techniques to analyse incomparable cost data, ignoring cost differences between networks and normalising costs by the same inappropriate factor does not provide reinforcing results but rather a repetition of errors.

The AER's misapplication of the PPIs together with the series of errors made in conducting the analysis render the results of AER's PPI analysis meaningless.

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[357] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 17

[358] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 35 and Attachment C2, Advisian, 2015, *Opex cost drivers ActewAGL Distribution Electricity (ACT),* January, page 102

[359] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 31

[360] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-61

3.4.4.8 *The AER's category analysis cannot substantiate benchmarking analysis*

The AER's category analysis is a form of PPI benchmarking that focuses on particular categories of opex in isolation. The AER states that the category analysis can be used to identify inefficiencies in the base year due to particular categories of opex:

> *We would not necessarily expect every metric to produce the same results because service providers may allocate opex across the categories differently. This is relevant to our analysis. For instance, a source of apparent inefficiency in the base year could be due to costs associated with a particular category of opex, for which there is a reasonable explanation for the high costs. Similarly, a service provider could appear to perform well on some category metrics but be inefficient overall. Category analysis is, however, useful for identifying areas of high cost and potential inefficiency.* [361]

ActewAGL Distribution rejects the results of the AER's flawed benchmarking model. Therefore, as a matter of principle, it is unnecessary to substantiate a set of unreliable econometric results through a further set of defective category analysis.

However, to ensure that the AER is able to reconsider the use of SFA econometric model and results (for reasons explained in Chapter 2 and throughout Chapter 3), and to help develop the regime of benchmarking as an investigate tool, ActewAGL Distribution submits its concerns with the AER's category analysis.

The AER's category analysis approach to its seven categories[362] consists of a few simple steps. The AER:

1. Takes data for each cost category and normalises it by a variable then plot the results against customer density. For example, labour costs per customer against customer density.
2. Provides high level commentary on the graphs generated for each cost category.
3. Finally, determines whether ActewAGL Distribution's costs are 'comparable', 'high' or 'very high'.

Based on these graphs the AER notes that ActewAGL Distribution performs poorly for most categories of expenditure and states that this supports the view that it is likely systematic issues

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[361] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-70

[362] Labour, total overheads, total corporate overheads, total network overheads, maintenance, vegetation management, and emergency response. Only the latter three relate specifically to opex.

exist across ActewAGL Distribution.[363] Without reference to any further investigation, analysis or evidence, the AER considered that the category analysis results are consistent with and support the findings of the AER's econometric benchmarking techniques.[364]

This approach, similar to AER's PPI analysis, is flawed. Category analysis cannot be used to make inferences regarding efficiency without further investigation. The AER makes this mistake despite recognising in the draft decision that category analysis is to be used to identify *potential* inefficiency. As the AER itself advises PPI analysis (and therefore category analysis) "…should not be viewed in isolation as a definitive assessment on the efficiency of an energy network business."[365]

Although the AER does conduct a detailed review of ActewAGL Distribution's labour practices and vegetation management (ActewAGL Distribution's concerns regarding these reviews is presented in Attachment C11) this is not sufficient. The AER defines material inefficiency to be when a service provider is not at (or close to) its peers on the efficient frontier.[366] To make inferences regarding relative efficiency all differences must be explored.

Notwithstanding this principal failing, in undertaking category analysis the AER makes the exact same errors in regards to data quality, one-dimensional nature of PPI benchmarking and assuming a linear relationship between inputs and outputs discussed in section 3.4.4.7.

As the AER misapplies category analysis and makes a similar series of errors as it did with the PPI analysis, the AER's category analysis is, like the AER's PPI analysis, meaningless and cannot be used to support the use of econometric benchmarking.

ActewAGL Distribution provides further comment in regards to the labour, overheads, maintenance and vegetation management categories below.

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[363] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-70

[364] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-70

[365] See Attachment C10, ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May, page 31

[366] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-37

Labour

The AER's category analysis of labour costs shows internal labour costs (opex and capex) per customer against customer density (Figure A.10). Labour costs include those allocated to opex and capex and excludes the use of external contractors. The AER notes that "ActewAGL appears to have a very high labour costs per customer relative to Energex, Endeavour Energy, AusNet, SA Power Network, Powercor and TasNetworks."[367] The AER recognises that the metric excludes contractor costs and concludes that the results are consistent with the economic benchmarking results.[368]

The AER's labour cost category is not, as the AER claims, a category of opex but a combination of total labour costs allocated to both capex and opex projects. The labour cost category is different to maintenance, vegetation management and emergency response, as it is not linked to a specific set of activities. What the labour category analysis does show is labour expenditure incurred across both opex and capex per customer.

The AER concludes that ActewAGL Distribution has "very high" relative labour expenditure costs and that ActewAGL Distribution performs poorly on this measure implying that this may be an area of potential inefficiency.[369] This logic is flawed. Inefficiency cannot be inferred through the comparison of a single input without consideration of:

1. Capex-opex trade-offs. Although the AER has considered both capex and opex labour costs, the AER has not examined the extent to which each DNSP substitutes internal labour for capital costs and vice versa. An example of this is the replacement or upgrade of assets which reduce the amount of maintenance required by internal labour or the prolonging the life of existing assets through higher levels of maintenance. DNSP's that substitute more capital assets for labour will have lower labour costs (but higher asset costs) and better "performance".

2. Input mix. The AER has not examined the extent to which each DNSP substitutes labour with other inputs. Examples include LiDAR aerial inspection versus ground based inspections, scaffolding versus elevated work platforms or fixed price contractors versus internal labour. The appropriate mix will be different for each business. However, even if

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[367] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-71

[368] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-71

[369] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-70

the technology choices were equally efficient they will influence each DNSP's "performance" on the AER's labour category.

3. Use of internal versus external labour. The data used is only internal labour meaning firms with higher levels of external contracting will "perform" better. The AER recognise that United Energy outsources at a higher level but does not account for differences between other DNSPs.
4. The volume of work or output. The AER has not taken into account unique cost drivers such as different asset configurations or the capex program in place

The AER has failed to adequately consider each of these issues (or provide any evidence or analysis) in addition to the issues that permeate all of the AER's PPI and category analysis: the quality of the underlying data, one-dimensional nature of PPI benchmarking, lack of adjustments for operating and environmental factors, and the assumed linear relationship between inputs and outputs. Accordingly, ActewAGL Distribution submits that the AER cannot draw any conclusions that labour costs are a source of inefficiency.

Overheads

The AER compares overhead costs using the following metrics:

- Corporate overheads per customer against customer density plotted by year;
- Network overheads per customer mapped against circuit km; and
- Total overheads (the sum of corporate and network overheads) per customer mapped against customer density.

The AER uses the total expensed (opex) and capitalised (capex) overheads allocated to standard control services. The AER concludes that ActewAGL Distribution has comparable corporate and network overheads but high total overheads.

The AER's conclusion is that ActewAGL Distribution's overheads are high relative to other DNSPs but when they are divided into corporate and network components the overheads suddenly become comparable. This contradiction, arising from a change in specification, highlights the fragility of the category analysis results. The AER's silence on this issue in the draft decision is concerning.

The AER state their reason for combining both opex and capex overheads is to "...ensure that differences in capitalisation policies do not affect this analysis."[370] ActewAGL Distribution notes

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[370] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-73

that this approach does not resolve all differences in cost reporting due to the application of different cost allocation methodologies and business practices, as detailed in section 3.4.4.5. Each DNSP allocates costs between overheads and direct costs differently.

Maintenance

The AER's category analysis of maintenance costs maps average maintenance expenditure per circuit km against customer density. The AER selected circuit kilometres to normalise cost data as the AER considers that assets are more likely to drive maintenance than customer numbers.[371]

The AER notes that ActewAGL Distribution "…appears to have very high costs compared to Ausgrid, Endeavour, Energex, Jen and UED but lower costs than Citipower"[372] and concludes that ActewAGL Distribution has "very high" relative costs.[373]

ActewAGL Distribution has identified a number of issues with the quality of data and results relied on by the AER to draw incorrect conclusions. For example, the category analysis suffers from:

- No adjustment for unique costs, such as backyard reticulation costs which are specific to ActewAGL Distribution.
- No consideration of different upstream network boundaries, and consequently, different maintenance responsibilities of different DNSPs. For example, there was no recognition that some networks receive part of their energy directly from the 22 kV system and therefore they do not have to incur the cost associated with maintenance of corresponding zone substation assets. These differences have been highlighted by Mr Glyde and Mr Mudge.[374] As Mr Glyde and Mr Mudge notes the multiple stage transformation and high voltage line assets in the NSW, ACT and QLD businesses results from both the transmission system design and decades old planning and design

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[371] The AER notes that circuit kilometres are an easily understood and intuitive measure of assets compared to transformer capacity or circuit capacity. AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-74

[372] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-75

[373] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-70

[374] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, pages 53 to 54

decisions which are not within the control of the business to change to any significant degree.[375]

- No consideration of different downstream network boundaries. For example, ActewAGL Distribution owns and maintains all of the underground service cables connecting customers to the electricity network, but this is not the case for all DNSPs. The boundary between ActewAGL Distribution's network and customer installation is typically at the meter box. This is not the case for a number of other businesses, where the network boundary is defined at the pit/pillar located in the street verge and consequently the service cable is owned by the customer.
- No consideration of different network assets within the same category of assets. For example, the portion of natural timber poles in the overall pole population varies significantly between the utilities. Also, the proportion of SWER lines which have lower maintenance requirements to other line construction types are not discussed by AER, despite the availability of RIN data which includes SWER lines.[376]
- Differing cost allocation methodologies and practises have not been accounted for in respect of maintenance costs. For example, Mr Glyde and Mr Mudge identified differences in capitalisation of pole top structures maintenance cost. [377] ActewAGL Distribution considers that these differences are likely to apply also to other activities such as emergency maintenance, installation of line spreaders, transformer oil replacement etc. However, the RINs do not include sufficient details to allow for quantitative assessments of these factors.
- No consideration of performance outcomes such as reliability, bushfire mitigation and other aspects of safety.

Given the large number of maintenance cost drivers the AER's one-dimensional nature of PPI is inadequate. While ActewAGL Distribution agrees that assets drive maintenance costs, circuit length cannot adequately capture the underlying drivers of maintenance costs. For example, other cost drivers not taken into account by the AER's category analysis include:

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[375] Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 52

[376] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, pag 58

[377] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, pages 78 to 80

- volume of network assets other that the circuit km used by AER e.g. transformer capacity, service cables;[378]
- maintenance requirements (and therefore costs) of different types of assets within the same asset category (e.g. timber poles versus concrete poles, SWER lines versus other types of lines[379]), which vary across networks;
- differences in maintenance responsibilities for assets registered which are owned by customers such as transformers owned by some high voltage customers.

These cost drivers are not uniform across DNSPs. As Mr Glyde and Mr Mudge notes the AER's frontier businesses are at a substantial natural advantage due to the relatively low volume of both line assets and transformer assets that they must maintain on a per customer basis.[380]

Mr Gylde notes that ActewAGL Distribution generally operates and maintains:

- *significantly less line assets per customer than the frontier business;*
- *significantly more zone and distribution substation assets per customer than the frontier business; and,*
- *significantly more underground network than the frontier business* [381]

Mr Glyde and Mr Mudge also notes that ActewAGL Distribution must operate and maintain, relative to the Victorian urban DNSPs:

- *36% more sub transmission line;*
- *40% more zone substation transformer capacity;*
- *108% more 11kV-33kV distribution lines;*
- *32% more distribution transformer capacity; and,*
- *38% more low voltage line.*[382]

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[378] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 45

[379] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, pages 58 to 59

[380] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 75

[381] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 46

When ActewAGL Distribution is compared to the customer weighted average of Victorian urban DNSPs this amounts to an extra:

- *41% more poles per customer;*
- *20% more route length per customer for an equivalent circuit length;*
- *36% more overhead line length per customer.* [383]

For these reasons Mr Glyde and Mr Mudge consider that the AER's category analysis for maintenance costs presents an incomplete view of the relative efficiency of ActewAGL Distribution's maintenance expenditure.[384]

Lastly, assuming a linear relationship does not recognise that some business costs associated with maintenance include a fixed cost component which are not directly proportional to the volume of network assets (e.g. mobilisation costs). For smaller DNSP's, such as ActewAGL Distribution, these costs are being spread across smaller volume of work.

Vegetation Management

The AER normalises vegetation management costs by overhead line length and maps the results against customer density.[385] The AER concludes that ActewAGL Distribution has very high costs compared to all other urban service providers.[386]

Firstly, as with other cost categories, the AER makes a series of errors in relation to data quality, partial nature of PPI benchmarking and the assumed linear relationship between inputs and outputs.

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[382] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 47

[383] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 48

[384] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 75

[385] As part of the vegetation management detailed review the AER normalises vegetation management costs by overhead *route* line length and again maps the results against customer density See: AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-81

[386] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-70

In terms of data quality the AER makes errors similar to other categories such as using data provided using different cost allocation methodologies and not taking into account unique costs, such as backyard reticulation. The AER also fails to adjust for the vegetation management cost pass through which occurred in 2012/13.

The AER does recognise data issues with regard to maintenance span length noting that:

> *Ideally, we would use maintenance span length. Maintenance span length measures the length of service providers' lines that have undergone vegetation management in the preceding 12 months. However, service providers' estimation assumptions seem to influence the data on maintenance spans. For some service providers maintenance spans are only a small part of overhead route line length, while for others they makes up the vast majority of overhead route line length. Therefore, we consider overhead route line length is a better measure of the area of network that requires vegetation management.*[387]

ActewAGL Distribution notes that the AER presents no analysis or evidence that the different proportions of vegetation maintenance spans of overhead route length is not driven by the varied presence of vegetation across networks. ActewAGL Distribution also notes that this acknowledgement brings into question the AER’s reliance on the Technical Advisory Group methodology which used kilometres of maintained vegetation corridor.[388]

Mr Glyde and Mr Mudge share the AER’s concerns regarding the consistency of the vegetation span data but note that it is not logical to simply ignore the data in a detailed assessment of vegetation management costs.[389] Mr Glyde and Mr Mudge compares the data to what would be expected given the geography of Australian vegetation and make an adjustment to overcome the data limitation. The results of Mr Glyde’s and Mr Mudge’s adjustments are presented in Figure 3.8.

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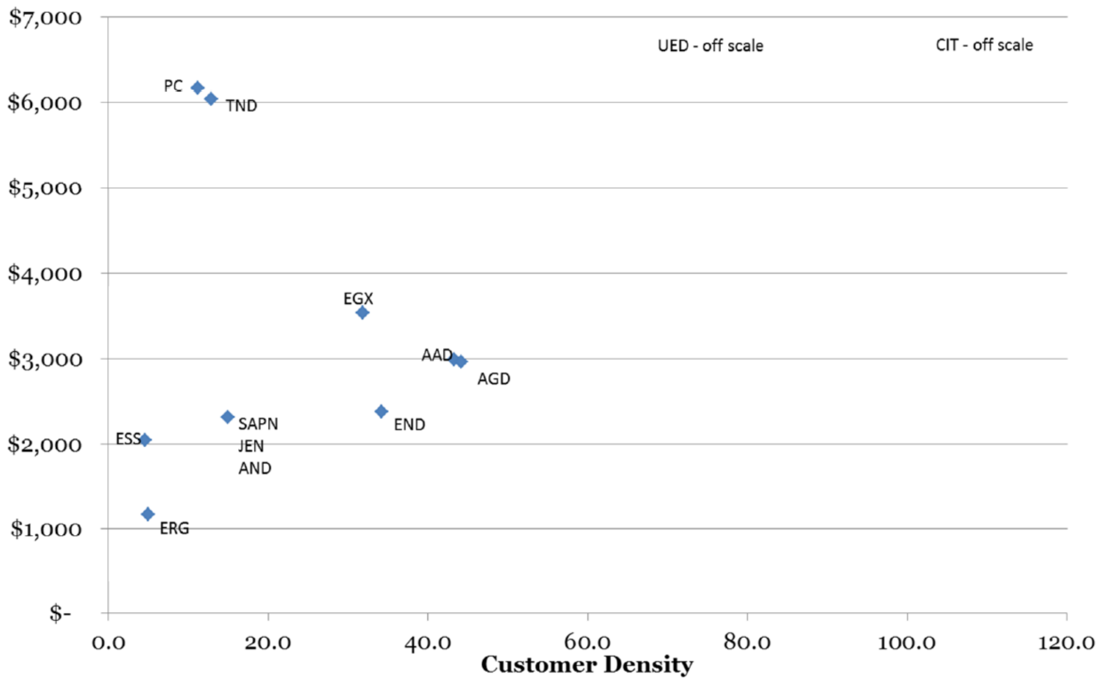
[387] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-76

[388] See Attachment C44, AER, 2014, *AER Technical Advisory Group: Advice on ActewAGL vegetation management cost pass through – Review of ActewAGL response to AER draft determination,* June, page 3

[389] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 68

While data issues remain, ActewAGL Distribution and Mr Gylde both note that Figure 3.8 contradicts the AER's conclusion that ActewAGL Distribution has very high costs relative to most of its peers.[390]

Figure 3.8 Average Vegetation Management costs per OH vegetation route km (Truncated vertical axis)[391]



Mr Gylde also finds that the AER overstates the overhead route km in a manner likely to adversely affect ActewAGL Distribution due to its high proportion of underground circuits.[392] Mr Glyde and Mr Mudge presents their preferred approach to apportion route kilometres in direct proportion to circuit kilometres. When this adjustment is made, shown in Figure 3.9, ActewAGL Distribution continues to compares well.

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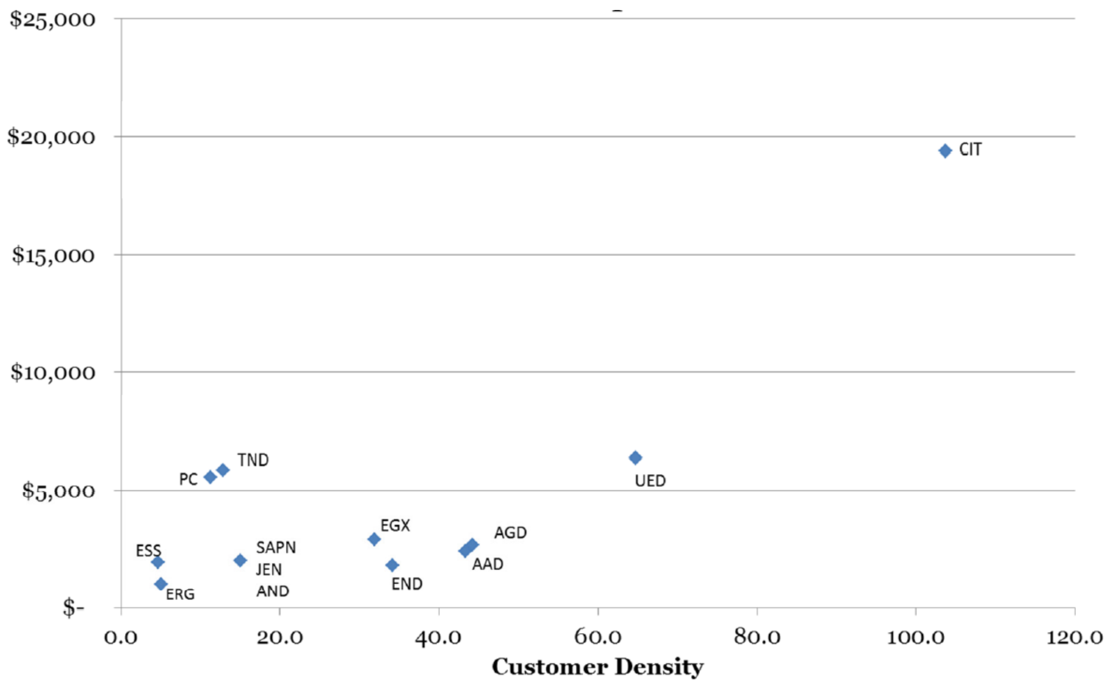
[390] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 71

[391] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 70

[392] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 65

Figure 3.9 Average Vegetation Management Costs per OH Vegetation circuit km[393]



As with other categories the AER's analysis does not take into account other factors which may influence its one-dimensional analysis.

ActewAGL Distribution has highlighted that Canberra is the 'Bush Capital' along with the extent of urban forest present in the ACT. These forested areas are also the predominate location for zone substations resulting in increased vegetation along connecting feeders. The AER commented that "…it may or may not be common for zone substations in other networks to be located in forested areas"[394] revealing the AER's lack of understanding of the extent to which vegetation affects each network. Without this understanding it is impossible to draw any conclusion on relative costs.

Secondly, the partial nature of category analysis benchmarking limits the number of factors that can be controlled for, such as the extent of vegetation discussed above or climatic factors which drive the extent of vegetation growth.

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[393] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 70

[394] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-76

The AER's category analysis also does not take into account the division of vegetation responsibilities. ActewAGL Distribution's vegetation management responsibility is different between rural and urban areas (in addition to its common law duty and legal obligations to provide a safe electricity network) as there are differences with other jurisdictions. Mr Glyde and Mr Mudge cite evidence from the Victorian Royal Bushfire Commission which shows that almost 90% of local councils in Victoria have some responsibility for the vegetation management of power lines.[395] Differences across all jurisdictions need to be taken into account.

Lastly, ActewAGL Distribution notes that the 2009 Victorian Bushfires Royal Commission recommended changes to distribution businesses inspection standards and procedures for all SWER lines and 22 kV feeders in high bushfire risk areas.[396] The AER's category analysis does not take into account changes in industry best practice over the time period. Importantly, under the Rules the AER's assessment of ActewAGL Distribution's proposed opex is not to assess relative costs but whether the proposed opex meets the opex objectives, such as the quality, reliability or security of supply of standard control services. The AER's lack of consideration of these objectives reinforces the inadequacy of the AER's assessment.

3.4.4.9 *The AER's detailed review of labour costs fails to substantiate benchmarking analysis*

The AER undertook a 'detailed review' of ActewAGL Distribution's labour levels, costs and practices and claimed that it 'uncovered labour and workforce inefficiencies'.[397] However, the AER's conclusions are based on flawed analysis and as such fail to serve as evidence to support its claims regarding ActewAGL Distribution's level of inefficiency and its alternative opex forecast.

ActewAGL Distribution's response to the findings of the AER's detailed review of labour is provided in Attachment C11 with a summary of key contentions below. This Section summarises ActewAGL Distribution's response to the AER's claims of:

- inefficient labour levels;
- inefficient labour costs;

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[395] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 67

[396] See recommendation 28 of Attachment C54, Teague AO, B., McLeod AM, R. and Pascoe AM, S., 2010, *2009 Victorian Bushfires Royal Commission Final Report Summary*, July, page 29

[397] AER 2014, *Draft decision – ActewAGL distribution determination 2014-19, Attachment 7: Opex*, November, p.7-32

- inefficiency with respect to:
    - outsourcing practices;
    - the use of redundancy provisions; and
    - organisation structural issues.

ActewAGL Distribution's labour levels are efficient

In its comparisons of labour levels, the AER is not undertaking an 'apples-with-apples' comparison. The AER adopts a simplistic approach of comparing Average Staffing Levels (ASL) across businesses. However, the AER fails to recognise that its analysis does not fully account for differences in outsourcing practices. Where a DNSP outsources a task it will report lower ASLs than a DNSP who undertakes the task internally, and hence appear more efficient in the AER's analysis. The results of such a comparison are driven by the sourcing models of the DNSPs and are not a measure of efficiency. As ActewAGL Distribution efficiently outsources less tasks than both New South Wales and Victorian DNSPs it is disadvantaged by the AER's simplistic analysis.

Further, the AER by comparing ASLs against customer numbers fails to recognise that it is actually the characteristics of the network that drive costs rather than customer numbers. In addition, a simplistic analysis of customer numbers takes no account of economies of scale. Larger networks are more likely to be able to access economies of scale and hence appear more efficient on a simple comparison of workforce numbers in comparison with a small DNSP such as ActewAGL Distribution. Economic Insights have identified the need to recognise scale impacts in reference to Envestra Qld, a small gas distribution network, where they state:

> *Simply comparing Envestra Qld opex partial indicators relative to group averages as WCC [a consultant] do takes no account at all of the all–important scale, customer density, energy density and opex/capex trade–off differences.*[398]

Similarly, Mr Glyde and Mr Mudge note the synergies available to Victorian DNSPs (against which ActewAGL Distribution is compared) and states:

> *These synergies were available due to the co-location of networks. This impacts AAD uniquely as these synergies are not available in the ACT due to the small size, geographical isolation of the ACT and absence of co-located networks within the same jurisdiction.* [399]

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[398] See Attachment C68, Economic Insights, 2011, *Review of AER Draft Decision on Envestra Queensland's Base Year Opex*, March, p.16

[399] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 93

ActewAGL Distribution considers that the AER has failed to substantiate its claim of inefficient labour levels and maintains its position that the labour levels of ActewAGL Distribution as implied in this revised regulatory proposal are efficient.

ActewAGL Distribution's labour costs are efficient

The AER claims that ActewAGL Distribution's labour costs are higher than other NEM service providers with respect to both labour cost per ASL and on a per customer basis.

In addition to the data comparability issues identified, the analysis presented by the AER is misleading. The AER's analysis of labour cost per ASL shows ActewAGL Distribution to be above the NEM average and the Victorian average (excluding United Energy). However, when this data is presented for the DNSPs individually, it is clear that ActewAGL Distribution is within the range of the Victorian DNSPs, with the exception of AusNet which has significantly lower reported labour costs and appears to be an outlier from the remaining businesses. This more detailed analysis also shows that the two most 'expensive' firms using labour cost per ASL are Powercor and CitiPower, the frontier firms from the economic benchmarking.

The AER has also previously recognised higher labour costs in the ACT through granting a real labour cost escalator above any other jurisdiction for the previous regulatory control period. There are also a range of other factors which lead to labour cost pressures in the ACT. These include the size of the market, competitors for labour hire within the market and skill shortages. Despite these pressures, analysis undertaken by Australian Business Lawyers & Advisors Pty Limited (ABLA) shows that ActewAGL Distribution does not stand out from its peers in regard to salaries contained in Enterprise Agreements (EAs).[400]

ActewAGL Distribution's workforce practices are efficient

The AER fails to provide evidence to support its claims on sources of labour inefficiency. It has also not afforded ActewAGL Distribution procedural fairness by failing to provide labour analysis undertaken by Deloitte upon which the AER relies to form its conclusions.

The AER's simplistic word-for-word comparison of the outsourcing provisions of EAs across DNSPs does not recognise that each EA provision interacts with other EA provisions, which it turn have a cumulative effect on operational flexibility. The AER has not provided evidence that supports its assertion that the restrictiveness of ActewAGL Distribution's EA is a source of inefficiency relative to its peers. ABLA found that contrary to the AER's conclusions, ActewAGL Distribution's EA is no more restrictive than most of its peers and in many respects is less so in

[400] See Attachment C72, ABLA, 2015, *Review and Comparison Of ActewAGL's Enterprise Agreement Provisions Against Other Electricity Network Service Providers,* January, page 4

relation to outsourcing, redundancy and business change generally.[401] The AER has also failed to provide evidence that demonstrates that higher levels of outsourcing deliver more efficient expenditure. Mr Glyde and Mr Mudge note: [402]

> *the question of whether network Opex or Capex tasks are carried out by internal or external labour is largely irrelevant to the efficiency of the outcome*

With respect to redundancy provisions, the AER claims that ActewAGL Distribution's access to involuntary redundancy is in contrast to the other DNSPs and that this may come at a cost to ActewAGL Distribution and be a driver of inefficiency.[403] Unlike other DNSPs, ActewAGL Distribution can undertake organisational restructuring from both voluntary and involuntary redundancies. While the cost of this may be high in the short term, the benefit is that change can be effected in a relatively short timeframe. ActewAGL Distribution considers the AER's contention that ActewAGL Distribution's relatively high redundancy payments during the 2009-14 period is evidence of inefficiency is flawed in the context of the incentive mechanism in place during this period and ActewAGL Distribution's investment in achieving longer term dynamic efficiencies.

The AER also cites structural and cultural issues identified in a major organisational review undertaken in 2011, and that as base opex has not materially reduced since this time, that these issues remain and provide evidence that ActewAGL Distribution has inefficient labour costs. ActewAGL Distribution has in fact implemented the review's recommendations. The AER's reliance on its identification that opex has not materially reduced fails to recognise that the achievement of efficiencies are factored into ActewAGL Distribution's implicit productivity growth rate factored into the opex forecast. Moreover, the incentives provided by the EBSS have provided the incentive to incur an efficient level of opex.

In summary, the AER's conclusions are based on flawed and incomplete analysis that fails to serve as evidence in support of its claims that ActewAGL Distribution's labour practices are inefficient. Therefore, the AER's detailed analysis does not corroborate the (equally flawed) SFA benchmarking results.

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[401] See Attachment C72, ABLA, 2015, *Review and Comparison Of ActewAGL's Enterprise Agreement Provisions Against Other Electricity Network Service Providers,* January, pages 4 to 5

[402] See Attachment C2, Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January, page 96

[403] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-79

3.4.4.10 *The AER's detailed review of vegetation management fails to substantiate benchmarking analysis*

The second part of the AER's 'detailed review' focuses on ActewAGL Distribution's vegetation management program. The AER formed the view that "…one of the sources of ActewAGL's high expenditure in its base year opex (identified with our benchmarking techniques) is likely due to vegetation management practices."[404] The AER states that the detailed review corroborates the benchmarking results.[405]

The AER provides no evidence or analysis that the purported inefficiencies identified corroborates the SFA benchmarking results, which indicate that ActewAGL Distribution is 40 per cent inefficient.[406] The AER does not identify a percentage or dollar amount of ActewAGL Distribution's proposed vegetation management operating expenditure it considers inefficient. Instead the AER simply claims that inefficiencies exist in ActewAGL Distribution's vegetation management practices.

The AER's inability to identify at least 40 per cent of ActewAGL Distribution's vegetation management expenditure as inefficient, in a cost category the AER considers to have 'very high' relative costs[407], undermines the SFA benchmarking results. This illustrates that the AER's draft decision opex allowance is not sufficient for ActewAGL Distribution to meet the opex objectives and will not achieve the NEO to the greatest degree.

The AER's analysis and identification of inefficiencies has the following flaws:

1. The AER's conclusion that ActewAGL Distribution's contracting arrangements were a key driver of inefficient vegetation management expenditure is based on incorrect and unsupported claims: ActewAGL Distribution primarily employs hourly rate contracting (incorrect), hourly rate contracting is potentially more inefficient (unsupported) and increasing contractor costs were a major contributor to increased costs (the increase in costs were a symptom of increased vegetation growth). The AER claims, without

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[404] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-79

[405] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-33

[406] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-27

[407] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-70

evidence or analysis, that ActewAGL Distribution could reduce costs through more proactive vegetation management. In making this claim the AER has no regard to evidence previously submitted that ActewAGL Distribution's vegetation management program is proactive.

2. The AER in concluding vegetation management performance deteriorated (by examining the increase in historical network outages due to vegetation) does not take into account the increase in vegetation growth over the period. While the number of vegetation related outages increased the impact of vegetation related outages did not, rural SAIDI and SAIFI declined significantly while urban SAIDI and SAIFI remained stable – indicating an improvement in performance.
3. The AER did not assess proposed vegetation management expenditure but the expenditure included within a 'base year opex' of the AER's own construction. The AER should instead assess actual costs proposed, which exclude the 2012/13 pass through amount which occurred due to unexpected and uncontrollable vegetation growth following two years of above average rainfall.

ActewAGL Distribution's response to the AER's detailed review is provided in Attachment C11.

3.4.4.11 *The AER's direct comparison benchmarking fails to substantiate benchmarking analysis*

The AER conducts direct comparison benchmarking by comparing ActewAGL Distribution's and Jemena Electricity Network's opex, customer numbers, circuit length and demand. The AER states that it compared ActewAGL Distribution and the Jemena Electricity Network "…to show that for a similar level of opex it is possible to produce a greater amount of outputs."[408] The AER's limits its analysis to customer numbers, circuit length and demand as outputs and concludes:

> *While this simplistic comparison does not account for differences between the service providers, it supports the findings of the more sophisticated benchmarking techniques, as well as the detailed analysis.*[409]

As outlined in the PPI and category analysis sections above, a simplistic comparison cannot provide any inference regarding efficiency without further detailed investigation.

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[408] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-34

[409] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-35

Ignoring this principal flaw, the AER's comparison does not take into account data issues (such as Cost Allocation Methodology differences between Jemena Electricity Networks (see section 3.4.4.5) or differences in the composition of assets (outlined in section 3.4.4.9).

The direct comparison, as with the PPI and category analysis, provides only a limited view of costs by selecting only three outputs– which means that the analysis excludes the impact of every single other factor not included. ActewAGL Distribution notes that the AER only selected cost drivers which also feature in its preferred econometric model and failed to examine any other potential cost drivers or outputs.

Given that the AER's direct comparison benchmarking faces the same data flaws and uses the same cost drivers, it is therefore unsurprising that similar results are found. The AER's direct comparison benchmarking, just like the AER's PPI and category analysis, does not corroborate the AER's econometric model nor 'reveal a diverse – but consistent – body of evidence'.[410]

3.4.4.12 *The AER's draft decision on base year opex does not contribute to the achievement of the NEO*

The AER's draft decision on base year opex does not contribute to the achievement of the NEO in that it delivers a short term price reduction at the expense of a significant deleterious impact on the long term interests of consumers with respect to quality, reliability, safety and security.

Professor Newbery notes that the exercise of regulatory discretion via the consideration of the entire regulatory package is in the long term interests of consumers:

> *Regulators operate under legislation that can impact on the level of discretion they are able to apply. However, an almost universal obligation on regulators is for them to have regard to the long-term interests of consumers. This clearly covers a range of factors, but the ongoing viability of the service provider is a critical aspect of this. Regulators need to have regard for the entire regulatory 'package' that they put in place. This ranges from the cost assessment through to the incentives and financeability of the service providers.* [411]

In Chapter 2, ActewAGL Distribution provides analyses and evidence that demonstrates that the effect of the reduction in opex allowance proposed by the draft decision has a deleterious impact on quality, reliability, safety and security. It will lead to staff reductions, reductions in maintenance and will undermine quality, reliability, safety and security.

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[410] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-68

[411] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 51

In addition, to the extent that the AER's draft decision on base year opex is not in accordance with law for the reasons advanced in previous Sections, it necessarily follows that that decision does not contribute to the achievement of the NEO and the AER's opex draft decision and overall draft decision cannot be said to be the decision that contributes to the achievement of the NEO to the greatest degree.

A decision that is not made in accordance with law, in the sense that it is not consistent with the NEL and the Rules and/or the requirements of administrative law could not be said to be a decision that contributes to the achievement of the NEO (or one which contributes to the achievement of the NEO to the greatest degree).

Such a construction of Section 16(1)(d) of the NEL is consistent with SCER's stated policy position concerning the intended effect of that provision as follows:[412]

> *[T]he regulator, in regulatory determination processes, and the Tribunal, in review processes, must … **where there is discretion around a range of decisions**, make the overall decision that, on balance, it considers is materially preferable in terms of serving the long term interests of consumers as set out in the NEO or NGO…* [emphasis added]

'Range of decision', in this context, means decisions that are in accordance with law. It does not include decisions which are not in accordance with the NEL and the Rules and the requirements of administrative law. Put another way, a decision that is not made in accordance with law could not be regarded as a 'NEO decision', that is, a decision which contributes to the achievement of the NEO.

Such a construction of Section 16(1)(d) of the NEL is also consistent with a presumption that the provisions of the NEL and the Rules promote their statutory object, being the NEO. Insofar as concerns the Rules, this is, in turn, consistent with the AEMC's express statutory obligation to make a Rule only if it is satisfied that the Rule will or is likely to contribute to the achievement of the NEO[413] and its statutory discretion to make a Rule that differs from a market initiated proposed Rule if the AEMC is satisfied that the more preferable Rule will or is likely to better contribute to the achievement of the NEO.[414]

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[412] See Attachment C45, SCER, 2013, *Regulation Impact Statement Limited Merits Review of Decision-making in the Electricity and Gas Regulatory Frameworks Decision Paper*, June, statement of 'SCER's policy position' in the preamble.

[413] See Section 88 of the NEL.

[414] See Section 91A of the NEL.

3.4.5 ActewAGL Distribution's revised base year proposal

This Section 3.4 has demonstrated clearly that the AER's mechanistic use of benchmarking to determine a base year opex allowance is fundamentally flawed in numerous ways. In placing such primacy on benchmarking, the AER has not complied with the procedural requirements of the Rules and has acted contrary to the scheme of the Rules. In addition, the econometric model suffers from severe technical deficiencies. The retrospective abandonment of the revealed cost approach and EBSS destroys incentives, breaks the regulatory contract and increases regulatory risk. ActewAGL Distribution considers that the AER's draft decision therefore does not contribute to the achievement of the NEO and is not in accordance with law.

ActewAGL Distribution maintains its view that the use of a revealed cost approach, in conjunction with an appropriate rate of change and step changes is a superior approach to determination of an opex allowance.

As such, ActewAGL Distribution's revised standard control base year opex calculation in provided in Table 3.9. ActewAGL Distribution notes that it varies to that of the regulatory proposal (see table 8.5 of that proposal) for the following reasons:

1. ActewAGL Distribution's financial auditors, Deloitte, identified a required adjustment to the 2012/13 reported opex as a result of amendments to the Australian Accounting Standard relating to employee entitlements (AASB 119 *Employee Benefits),* to apply for reporting periods beginning on or after 1 January 2013. This resulted in a retrospective downward adjustment of $0.42 million to 2012/13 reported standard control opex.
2. The adjustment for miscellaneous charges, which was made due to a reclassification of these services from standard control to alternate control, has decreased by $0.76 million to account for the allocation of quoted services revenue in the base year, which in the previous regulatory control period was treated as an adjustment against expenditure.
3. While reviewing the corporate overhead adjustment impact in response to a query from the AER, an error in ActewAGL Distribution's base year adjustment to account for the change in the cost allocation method (CAM) was discovered. This involved the inclusion of a depreciation component for corporate services which should not have been included. The AER was notified of this issue.
4. ActewAGL Distribution's revised base year opex forecast uses a base year approach, rather than a combination of base year and zero based forecasting approaches. The approved vegetation pass through for 2012/13 has been excluded.

Table 3.9 Standard control 2012/13 base year opex ($ million, 2012/13 dollars)

RIN reported 2012/13 total opex	**95.4**
Revised 2012/13 total opex	**95.0**
Adjustments	
FiT	(14.1)
UNFT	(5.5)
Energy Industry Levy	(0.7)
Miscellaneous charges	(2.7)
Actual adjusted opex	72.0
CAM Adjustment	(6.9)
Actual base year operating expenditure adjusted for CAM	65.1
Less non-recurrent costs	
Comcare exit payment	(1.8)
Vegetation management pass through	(1.9)
Adjusted efficient base year opex	**61.4**
Adjusted efficient base year opex ($2013/14)	**63.1**

3.5 Rate of change

3.5.1 ActewAGL Distribution's proposal

ActewAGL Distribution's regulatory proposal included forecast opex to account for price and output changes over the forthcoming regulatory control period, but did not include an explicit allowance for productivity changes as implicit productivity gains were factored into the total opex forecast.

3.5.2 AER draft decision

The AER's draft decision includes an overall rate of change forecast of 0.66 per cent higher on average than ActewAGL Distribution's over the forecast period according to the AER's analysis. This is made up of the following components:

- on average forecast price change 0.16 percentage points lower ;
- on average forecast output change 0.82 percentage points higher; and
- the same forecast of productivity change, being zero.

The AER's analysis of the rates of change proposed by ActewAGL Distribution and those included in the AER's draft decision is provided in Table B.4 of the draft decision. [415]

3.5.3 ActewAGL Distribution's response and revised proposal

3.5.3.1 *Price change*

The change in prices accounts for the price of key inputs that do not move in line with the CPI and form a material proportion of ActewAGL Distribution's expenditure. The AER's draft decision on price change is for a rate made up of labour price changes and non-labour (which includes materials). The AER adopted a weighting of 62 per cent for labour price and 38 per cent for non-labour. The labour price change is based on forecasts of the Electricity, Gas, Water and Waste services (EGWWS) industry and CPI forecasts for non-labour.

The AER's lower price change forecast is a result of a different apportionment of opex between labour and non-labour, and the use of an average of labour price escalators forecast by Independent Economics, as proposed by ActewAGL Distribution, and those forecast by Deloitte Access Economics (DAE) on behalf of the AER. Additionally, the AER's opex model fails to allow for price growth in the year between the base year and the first year of the 2014-19 regulatory control period (i.e. 2013/14), resulting in the allowance for price change to be understated in all years of the regulatory control period. For the forecast to accurately reflect real price growth, it should account for cumulative growth from the base year.

The AER's assessment approach is the same as that employed for SP AusNet's gas distribution determination, being an average of two forecasts having regard to historical performance of these forecasts. The AER averaged the DAE and BIS Shrapnel forecasts (proposed by SP AusNet) as it had found DAE to typically under-forecast and BIS Shrapnel to typically over-forecast. [416]

The AER states that it cannot assess the past accuracy of Independent Economics forecasts as they have not provided labour forecasts in past decisions.[417] This is not the case.

The AER engaged KPMG Econtech to prepare labour cost escalation forecasts for ActewAGL Distribution's 2009-14 distribution determination. Econtech partnered with KPMG in 2008 to

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[415] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-132

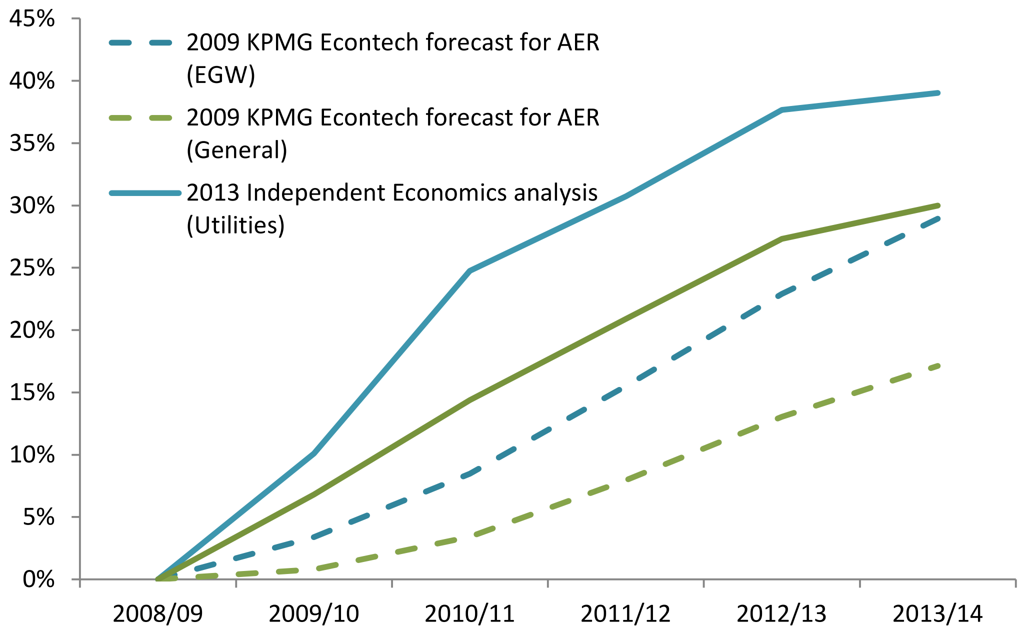
[416] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-136

[417] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-136

become KPMG Econtech for three years, and then subsequently adopted the trading name of Independent Economics.[418] Therefore ActewAGL Distribution is of the view that the AER can consider the past accuracy of Independent Economics' forecasts, based on its own use of these forecasts.

Figure 3.10 shows the comparison in cumulative nominal average wage growth since 2008/09 forecast by KPMG Econtech for the AER's final decision for ActewAGL Distribution's 2009-14 determination against the actual nominal growth according to analysis by Independent Economics for ActewAGL Distribution in 2013/14. This shows that, like DAE, Independent Economics has previously under forecast labour cost growth.

Figure 3.10 Econtech/Independent Economics' cumulative forecast and actual nominal wage growth since 2008/09



Source: ActewAGL Distribution

As noted in Section 3.2.1, the Tribunal has had cause to consider the first of the Revenue and Pricing Principles as set out in Section 7A(2) of the NEL relating to the requirement for service providers to be provided with a reasonable opportunity to recover at least the efficient costs the

[418] Independent Economics, 2011, *Our History*, accessed 16 January 2015, <http://www.independenteconomics.com.au/Our%20History.aspx>

operator incurs, and considers it necessary to err on the side of allowing service providers to recover at least its efficient costs the regulatory framework to achieve the opex objectives.

The AER's approach in the draft decision (of averaging the labour growth forecasts) does not provide a realistic expectation of the cost inputs required to achieve the operating expenditure objectives nor errs on the side of allowing at least the recovery of efficient costs as required by the NEL.

Based on the evidence available to the AER the labour forecasts of both firms have been lower than actual growth. To take historical forecast accuracy into account, using the same assessment approach the AER employed for SP AusNet, ActewAGL Distribution considers a realistic expectation of cost inputs would be best reflected by the higher of the two, and therefore Independent Economics' updated forecasts should be applied. This approach will provide ActewAGL Distribution with a greater opportunity to recover at least its efficient costs and in turn contribute to the NEO to the greatest degree.

Opex price weightings

In its draft decision, the AER adopted weightings of 62 per cent for labour and 38 per cent for non-labour for price escalation. This is a lower labour weighting than the AER has referred to elsewhere in the draft decision of approximately 80 per cent.[419] The AER's adopted weightings are claimed to be broadly consistent with Economic Insight's benchmarking report which applied weight of 62 per cent EGWWS wage price index (WPI) for labour and 38 per cent for five producer price indexes for non-labour.

The AER fails to provide any basis for, or evidence to support, the adoption of these weightings, nor is any basis, or evidence, for these weightings advanced in Economic Insights' benchmarking analysis. ActewAGL Distribution revised forecast is based on ActewAGL Distribution's estimate of the actual weightings between labour and non-labour in the base year and for each of the proposed step changes.

Further, ActewAGL Distribution observes that, as the AER has not disclosed the basis for its opex price weightings in its draft decision, ActewAGL Distribution has been denied the opportunity to respond to the AER's draft decision on those weightings. Accordingly, if the AER is minded to rely on the opex price weightings proposed in its draft decision in making its final decision, the AER must first make known to ActewAGL Distribution the basis for those weightings and provide it with a reasonable opportunity to make submissions on those weightings, in accordance with the

[419] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-32, and confidential appendix to attachment 7, page 7

AER's obligation under s16(1)(b) of the NEL and its common law obligation to accord procedural fairness.

Updated labour cost escalators

For the purposes of the regulatory proposal, ActewAGL Distribution applied labour cost escalators consistent with those applied for the transitional regulatory proposal. These were forecast by Independent Economics in December 2013. As foreshadowed in ActewAGL Distribution’s regulatory proposal, these forecasts have been updated to include additional historical data that has become available since the previous forecast and to reflect changes in economic conditions that have impacted forecasts. Independent Economics’ updated labour cost escalators are provided at Attachment C46. Independent Economics’ advice on updated nominal forecast escalators has been used by CEG to develop real cost escalators, which is provided at Attachment C47. The revised forecast shows a weakening in labour cost growth, as explained in the report.[420] The utilities labour growth forecasts are provided in Table 3.10 below, which also shows the labour cost escalators proposed in ActewAGL Distribution’s regulatory proposal and the AER’s draft decision for comparison. As noted previously, the AER opex forecast fails to allow for price growth in 2013/14, which has a flow on effect for cumulative growth in each year of the regulatory control period.

Table 3.10 Real utilities labour cost escalators 2014-19

(per cent)	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Regulatory proposal annual escalators	2.4	0.6	1.6	2.1	2.1	2.1
Regulatory proposal cumulative escalators	2.4	3.0	4.7	6.9	9.2	11.4
AER draft decision annual escalators	Not included	0.8	1.0	1.4	1.5	1.2
AER draft decision cumulative escalators	Not included	1.8	2.8	4.3	5.8	7.1
Revised proposal annual escalators	**2.2**	**1.8**	**1.3**	**1.7**	**1.5**	**1.5**
Revised proposal cumulative escalators	**2.2**	**4.1**	**5.5**	**7.3**	**8.9**	**10.5**

[420] See Attachment C46, Independent Economics, 2014, *Update of labour cost escalators for NSW and the ACT*, November, pages 5 to 6 and Attachment C47, CEG, 2015, *Updated cost escalation factors*, January, pages 4 to 5

ActewAGL Distribution's revised proposed forecast price change

ActewAGL Distribution's revised proposed forecast opex to account for price change is provided in Table 3.11. The difference between ActewAGL Distribution's previous forecast and the revised forecast is due to lower labour escalation forecasts as a result of changes in economic conditions. The difference between ActewAGL Distribution's revised proposed forecast and the AER's draft decision is due to the following:

- higher proposed base opex;
- Higher labour cost escalation; and
- Allowance for real cost escalation in 2013/14, which was not included in the AER's opex forecast.

Table 3.11 Forecast real price change 2014-19

($2013/14)	2014/15	2015/16	2016/17	2017/18	2018/19
Regulatory proposal forecast price change (per cent)	0.77	1.59	2.69	3.68	4.76
Regulatory proposal forecast price change ($million)	$0.58	$1.16	$1.89	$2.66	$3.47
AER draft decision forecast price change (per cent)	0.53	0.79	1.90	2.97	3.44
AER draft decision forecast price change ($million)	$0.22	$0.33	$0.80	$1.25	$1.45
Revised forecast price change (per cent)	**1.73**	**2.35**	**3.19**	**3.83**	**4.51**
Revised forecast price change ($million)	**$1.27**	**$1.71**	**$2.23**	**$2.74**	**$3.26**

3.5.3.2 *Output and productivity change*

ActewAGL Distribution's proposal

In its regulatory proposal ActewAGL Distribution explained that its asset management software, Riva, produces plans for each asset type and forms the basis of the zero-based maintenance forecast. As only select assets have been included in Riva not all maintenance costs have been included in planned maintenance costs. The amount of total forecast operating expenditure attributable to output growth for each year of the 2014–19 regulatory control period is given by the maintenance costs of assets related to output growth to be commissioned included in the forecast.

The proportion of total forecast operating expenditure attributable to output growth changes and included in ActewAGL Distribution's forecast is small. Maintenance costs for less than 20 assets expected to be commissioned have been included and totalled only $0.43 million for the period.

In its regulatory proposal ActewAGL Distribution explained that it had used an implicit productivity improvement in developing forecast operating expenditure rather than explicit productivity or output growth factors. ActewAGL Distribution's approach assumed that the increased costs from output growth, illustrated by a forecast 22 per cent increase to the regulatory asset base and an additional 12,000 customers, would be offset by increases to productivity to maintain a stable operating cost profile.

AER draft decision

The AER's draft decision on output change is to adopt output measures and respective weightings consistent with those used in Economic Insights' opex cost function analysis undertaken for the AER. This includes customer numbers (67.6 per cent), circuit length (10.7 per cent) and ratcheted maximum demand (21.7 per cent).[421]

In its draft decision on forecast productivity change, the AER similarly relies on the analysis of Economic Insights and its own expectations of productivity trends in the distribution industry. Economic Insights' econometric modelling of partial productivity forecasts resulted in negative growth rate forecasts between 2014 and 2019, at an average of -1.59 per cent.[422] After giving consideration to the impact of step changes included in opex allowances in recent AER resets, the outlook for future DNSP output growth in terms of demand, and concerns with the incentive effects of allowing a negative productivity growth rate, Economic Insights formed a view that a productivity growth rate of zero should be used in the rate of change formula.[423]

ActewAGL Distribution's response and revised proposal

ActewAGL Distribution has detailed its concerns regarding the AER's use of the opex cost function derived from Economic Insights' econometric modelling including technical errors in Section 3.4.4.5. Consistent with these contentions, ActewAGL Distribution does not consider the

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[421] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-144

[422] Economic Insights, 2014, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November, page 40

[423] Economic Insights, 2014, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November, pages 55 to 57

basis for AER's draft decisions on both output and productivity change to reasonably reflect the efficient costs a prudent operator would incur to achieve the opex objectives. Consequently ActewAGL Distribution maintains its proposal to include an allowance for output growth based on new asset maintenance costs, with an implicit productivity growth factor included. Table 3.12 below provides ActewAGL Distribution's proposed output growth forecast against the AER's draft decision.

Table 3.12 Forecast output growth

($2013/14)	2014/15	2015/16	2016/17	2017/18	2018/19
Regulatory proposal forecast (per cent)	0.03	0.10	0.13	0.15	0.18
Regulatory proposal forecast ($million)	0.02	0.07	0.09	0.11	0.13
AER draft decision forecast (per cent)	-0.04	1.36	2.24	3.26	4.72
AER draft decision forecast ($million)	-0.02	0.57	0.94	1.37	1.98
Revised forecast (per cent)	**0.03**	**0.10**	**0.13**	**0.15**	**0.18**
Revised forecast ($million)	**0.02**	**0.07**	**0.09**	**0.11**	**0.13**

3.6 Step changes

3.6.1 ActewAGL Distribution's proposal

ActewAGL Distribution's regulatory proposal included nine step changes above the base expenditure considered necessary to achieve the operating expenditure objectives under Clause 6.5.6(a) of the Rules. These step changes totalled $35.3 million above the base expenditure.

The step changes proposed by ActewAGL Distribution were driven by both changes in regulatory obligations and changes in ActewAGL Distribution's policies and strategies considered necessary to continue to achieve the operating expenditure objectives under Clause 6.5.6(a) of the Rules. ActewAGL Distribution considers the step changes proposed reasonably reflect the operating expenditure criteria under Clause 6.5.6(c).

3.6.2 AER draft decision

The AER's draft decision on opex step changes is set out in Appendix C to Attachment 7 to the draft decision. The AER states that it typically allows step changes to base operating expenditure for changes to ongoing costs associated with new regulatory obligations and for efficient capex/opex trade-offs. The AER's draft decision includes a step change of $1.4 million related to increased regulatory compliance costs, which represents just four per cent of ActewAGL

Distribution's proposed step change in expenditure. In making this decision, the AER states that it was not satisfied that adding step changes for other cost drivers would lead to an opex forecast that reasonably reflects the opex criteria.[424]

3.6.3 ActewAGL Distribution's response and revised proposal

ActewAGL Distribution considers the AER's position of only allowing step changes for ongoing costs associated with new regulatory obligations and for capex/opex trade-offs, and therefore its draft decision on ActewAGL Distribution's proposed step changes, to be inconsistent with the Rules.

The scope of opex step changes must be determined by reference to the statutory test for the AER's acceptance of a DNSP's proposed opex forecast. Having regard to Clause 6.5.6(c) of the Rules, ActewAGL Distribution contends that the AER must accept a proposed step change where it is necessary for forecast opex to reasonably reflect the opex criteria, being the efficient costs of achieving the opex objectives in Clause 6.5.6(a) of the Rules, the costs that a prudent operator would require to achieve those objectives, and a realistic expectation of the demand forecast and cost inputs required to achieve those objectives. Accordingly, the nature of changes to forecast opex relative to base year opex that may constitute step changes depends upon the content of the opex objectives in Clause 6.5.6(a) and is not confined to opex changes arising from changes in regulatory obligations or requirements and capex/opex trade-offs.

As a result the Rules require the AER to accept a proposed step change which is not due to a change in a regulatory obligation or requirement or a capex/opex trade-off where the step change is necessary for forecast opex to reasonably reflect the efficient costs of achieving the opex objectives, the costs that a prudent operator would require to achieve those objectives, and a realistic expectation of the demand forecast and cost inputs required to achieve those objectives.

Having regard to the opex objectives a step change in forecast expenditure above or below base year opex could be required for the following reasons:

- a change in a regulatory obligation or requirement; or
- where base year opex was insufficient to achieve compliance with the regulatory obligations and requirements applicable in the base year; or
- a change in the expected demand for standard control services which is not otherwise provided for in the rate of change; or

[424] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-144

- where base year opex was insufficient to meet or manage the demand for standard control services experienced in the regulatory control period in which the base year occurs; or
- where base year opex is not sufficient to maintain:
    - the quality, reliability and security of supply of standard control services (to the extent that there is no applicable regulatory obligation or requirement in relation to that quality, reliability and security); or
    - the reliability and security of the distribution system through the supply of standard control services (to the extent that there is no applicable regulatory obligation or requirement in relation to that quality, reliability and security); or
    - the safety of the distribution system through the supply of standard control services.

ActewAGL Distribution is of the view that the term 'maintain' in Clause 6.5.6(a) of the Rules should be read such that:

- the phrase 'maintain the safety of the distribution system' is taken to mean to keep the distribution system secure from liability to harm, injury, danger or risk; and
- to the extent there are no regulatory obligations or requirements applicable in respect of any aspect of reliability, quality or security, the phrase 'maintain quality, reliability or security' is properly construed to mean to keep in continuance or preserve quality, security and reliability (as applicable), which terms do not have any absolute, specific or certain character.

Consequently, a step change should be allowed if forecast opex would otherwise be inadequate to keep the distribution system secure from liability to harm, injury, danger or risk, or to keep in continuance or preserve acceptable quality, security and reliability.

It is on the basis set out above that ActewAGL Distribution maintains the proposed step changes as part of its revised opex forecast. In addition, ActewAGL Distribution proposes an additional step change for asset management optimisation as discussed in section 3.6.3.6. A summary of ActewAGL Distribution's proposed step changes is provided in Table 3.13 below. These costs have not been escalated to account for real price change.

Table 3.13 Standard control operating expenditure step changes

($ million, 2013/14)	Regulatory proposal	Draft decision	Revised proposal
EHSQ	2.8	0.0	2.8
Regulatory compliance and strategy	8.6	1.4	8.6
Network operations and call centre	2.1	0.0	2.1
Technical standards	1.4	0.0	1.4
Contractor management	3.1	0.0	3.1

Works practices	3.5	0.0	3.5
Network IT support	4.8	0.0	4.8
Corporate services charges	10.1	0.0	17.0
Allocation of corporate services charges	-1.2	0.0	-0.2
Asset management optimisation	0.0	0.0	1.1
Total step changes	**35.3**	**1.4**	**44.1**

ActewAGL Distribution's response to specific matters raised in the AER's draft decision on each of the proposed step changes is detailed below.

3.6.3.1 *Environment, health, safety and quality step change*

Overview

The AER's draft decision does not allow a step change of $2.8 million for a number of activities related to health and safety including injury prevention, bushfire mitigation, climate risk and resilience, and unplanned safety events.[425]

The EHSQ opex step change is for costs not included in the base year or accounted for in the rate of change but are required to achieve the operating expenditure objectives under the Rules, specifically to:

- comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
- the extent that there is no applicable regulatory obligation or requirement, to maintain the quality, reliability or security of supply of standard control services, the reliability and security of the distribution system through the supply of standard control services; and
- maintain the safety of the distribution system through the supply of standard control services.

The costs included in this step change are for the use of external specialists in the areas of; bushfire mitigation, climate change, mandated independent asbestos removal (in the ACT), health monitoring and surveillance, and other expenses (classified as 'other' costs). These specialised skills are not core internal skills at ActewAGL Distribution. Therefore, it is not cost

[425] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-149

effective, and in some cases illegal to deliver these services using existing internal resources. The specific external drivers of these step changes are:

1. *Work Health and Safety Act 2011,* Regulations, and Codes of Practice being incorporated into ActewAGL Distribution's internal systems.
2. Detailed assessments and introduction of identified controls to exercise the WHS Act, Officer, Primary Duty of Care and other management duties.
3. ActewAGL Distribution to take a new role of shared responsibility under the revised Strategic Bushfire Management Plan 2014 which is an instrument under Section 80 and Section 74 of the *Emergencies Act 2004*.
4. Incorporate the amendments to the anti-bullying legislation (effect 1 January 2014) under the *Fair Work Act 2009*.
5. Introduction of ongoing changes to asbestos management with the new *Dangerous Substances (Asbestos Safety Reform) 2014* and two new asbestos codes of practice, commencing 1 January 2015.
6. Changes of environmental laws in the ACT.

Work health and safety

In response to the AER draft decision regarding harmonised laws and the intent for those harmonised laws to reduce regulatory burden,[426] two points need to be made.

Firstly, according to Safe Work Australia's regulation impact statement, the reduction in compliance costs for multi-state businesses should equate to lower compliance costs however for single-state businesses, such as ActewAGL Distribution, the outcome is unclear.[427]

Secondly, true harmonisation has not occurred as per the recent COAG [428] report which identifies that uniform OHS laws are only partially complete. In particular, Queensland and ACT governments passed laws with material differences, Victoria and Western Australia have not introduced the harmonised model laws, South Australia introduced the model laws in 2013 and the remainder of the States have passed the model laws that do not materially differ.

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[426] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 148

[427] See Attachment C48, Safe Work Australia, 2011, *Decision Regulation Impact Statement for National Harmonisation of Work Health and Safety Regulations and Codes of Practice*, November, page 19

[428] See Attachment C49, COAG Reform Council, 2013, Seamless National Economy: Final Report on performance, December

The AER's draft decision states:

We examined whether requirements under the WHS Act 2011 were more onerous than the requirements under its predecessor, the Work Safety Act 2008 but have found no evidence that the obligations under the Work Health Safety Act 2011 are more onerous than the requirements which existed under the Work Safety Act 2008.[429]

ActewAGL Distribution considers this to be an inadequate, inaccurate and subjective assessment by the AER. The WHS Act 2011 is a new law with new and broader definitions and concepts than in previous laws. In order to comply with the new WHS Act, Regulation and Codes of Practice additional costs have been and will continue to be incurred.

For a single-state business such as ActewAGL Distribution, the opex costs increased in the 2009-2014 regulatory control period and included the employment of additional health and safety professionals, discussions with safety lawyers to understand the new WHS Act and WHS Regulation definitions and how to best exercise and discharge the new duties to meet Section 19, as well as the writing of new process/procedures, consultation, implementation and training of new practices and requirements. This will continue into the 2014-19 regulatory control period as changes continue to occur to the WHS Act, Regulation and implementation of new Codes of Practice.

Following the introduction of new *Work Health and Safety 2011 Act* (WHS Act) and *Work Health and Safety Regulation 2011* (WHS Regulation) which came into effect in the ACT from 1 January 2012, it became clear that to ensure obligations and duties under the new laws were being met, there was a requirement to undertake more detailed risk assessments. The intent of the assessments was and continues to be to ensure identified risks are eliminated or reduced to so far as is reasonably practicable. The consequence is that the changes in law and requirements have and will continue to result in a material increase in opex costs.

The new WHS Act 2011[430] introduced terminology and broader concepts such as:

- a Person Conducting a Business or Undertaking (PCBU);
- officer duties;
- others having duties;
- duties relating to designers, and those constructing, installing, and commissioning; and

[429] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 148

[430] ACT *Work Health and Safety Act 2011*, subdivision 1.3.2 and Part 2

- expanded duties relating to managers.

The far reaching and much broader Section 19 of the WHS Act, relating to the primary duty of care and the six key officer duties specified in Section 27, means that ActewAGL Distribution's Board members, executive and managers must ensure they exercise and discharge these personal duties. They must ensure, so far as is reasonably practicable, that the health and safety of workers and other persons, including the public, is not put at risk from the distribution network or work carried out as part of the conduct of the business or undertaking.

Additionally, ActewAGL Distribution's Board, executive and managers must ensure that the business or undertaking has available for use, and uses, appropriate resources (people, plant, equipment, substances and materials) and processes to eliminate or minimise risks to health and safety from work carried out as a part of the conduct of the business or undertaking. As such, a risk assessment approach is utilised to analyse work activities within the context of various environments throughout the ACT in order to meet the various WHS Act duties. Assessments are required as per Sections 17 and 18 of the WHS Act, to examine available and suitable ways, such as codes, standards (Australian, international or industry) or guides to eliminate or minimise identified risks to so far as is reasonably practicable. Only after assessing the extent of the risk and the available ways of eliminating or minimising the risk, the costs associated with available ways of eliminating or minimising the risk, including whether the cost is grossly disproportionate to the risk, is examined. As such, cost is only relevant if it is grossly disproportionate to the risk level and is not the key driver to discharging the various duties and obligations.[431] Cost is not a sufficient justification for choosing a lower order safety control measure or deciding to do nothing, particularly where the WHS Regulation and related Codes of Practice and standards indicate the level of control/s required. In fact, the ACT WorkSafe inquiry into safety within ACT's construction industry and the New Zealand's Department of Labour report into safety, both identify that the upfront opex into safety far outweighs the costs and outcomes of reducing or not investing in safety.[432]

ActewAGL Distribution does not agree with the AER's claim that the Codes of Practice are not new obligations or legally required.[433] A relevant Code of Practice is admissible as evidence in

[431] ACT *Work Health and Safety Act 2011*, sections 17 to 19 and section 27

[432] See Attachment C50, ACT WorkSafe, 2012, *Getting Home Safely – Inquiry into Compliance with Work Health and Safety Requirements in the ACT's Construction Industry*, November, page 20 and Attachment C51, Department of Labour (New Zealand), 2007, *How Health and Safety Makes Good Business Sense,* August, pages 28-30

[433] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 150

any court proceeding under the Act or the Regulations. As previously explained, a court may also rely on the Code of Practice in determining what is reasonably practicable (the risk management duties contained within the WHS Act) in the circumstances to which the Code of Practice relates.[434] As new Codes of Practice are released under the new WHS Act, ActewAGL Distribution considers that as a minimum it has a requirement to adhere to these and failure to do so would risk both ActewAGL Distribution and its officers discharging their WHS duties.

From 2011 to 2014, Safe Work Australia released 23 Codes of Practice.[435] Currently the ACT has released 20 Codes of Practice and there are 13 Codes of Practice listed by ACT WorkSafe that are expected to be introduced during the 2014-19 regulatory control period. Complying with the new Codes of Practice is required to ensure ActewAGL Distribution can demonstrate that it has met the WHS Act risk management and primary duty of care duties and as such ActewAGL Distribution will require a material increase in expenditure during the 2014-19 regulatory control period.

The broader personal and proactive Section 27,[436] regarding officer duty has also resulted in increased costs from the base year associated with restructuring the governance arrangements in order to satisfy Section 27 of the WHS Act. Increases costs relate to:

- new and ongoing officer training to ensure officers acquire and maintain up-to-date work health and safety knowledge;
- increased assurance activities to ensure the business has available for use; and
- use of appropriate resources and processes to eliminate or minimise work health and safety risks and specific incident and hazard reporting.

The new WHS Regulation 2011 was not completely commenced on 1 January 2012. Several Sections, divisions and parts remained 'un-commenced' in 2012 and were slowly released throughout 2013.[437]

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[434] ACT *Work Health and Safety Act 2011,* Section 274 to 275

[435] Safe Work Australia, 2014, *Model Codes of Practice*, accessed 16 January 2015, <http://www.safeworkaustralia.gov.au/sites/swa/model-whs-laws/model-cop/pages/model-cop>

[436] ACT *Work Health and Safety Act 2011*, Section 27[437] ACT *Work Health and Safety Regulation 2011*, Endnote 3, page 439[438] ACT *Work Health and Safety Regulation 2011,* Section 58

[437] ACT *Work Health and Safety Regulation 2011*, Endnote 3, page 439[438] ACT *Work Health and Safety Regulation 2011,* Section 58

In addition, the *Fair Work Act 2009* anti-bullying amendments which came into effect on 1 January 2014 require ActewAGL Distribution to educate employees on psychological health.

Release of further codes over the 2014-19 regulatory control period will require further updating of relevant safety policies, procedures and safe work method statements. In addition to reviewing and updating documentation, governance and training, the changes to these legislative instruments have resulted in the need to undertake additional ongoing activities to ensure new obligations are being met by ActewAGL Distribution workers, contractors and others that may be working on, near or potentially affected by the distribution network.

The new WHS Act, along with the WHS Regulations and continual introduction of Codes of Practice requires a step change in opex associated with resources risk assessing, updating and implementing (includes training) processes, practices, tools and equipment as follows:

a. Health monitoring / surveillance had not previously been undertaken in ActewAGL Distribution. This involves medical examinations and tests as per the WHS Act, Sections 19 and 20, WHS Regulation, and Codes of Practice:
   i. Assessments of plant/equipment, assets and work activities. In 2013 it was identified that health surveillance and monitoring tests are required;
   ii. 2013/14 introduced new baseline medicals for audiometric testing as per WHS Regulation and requirement for testing 3 months before commencing work and at least every 2 years[438] as well as asbestos health testing; and
   iii. As a result of the assessment activities, a new full health monitoring and ongoing surveillance program commences in 2015/16 for staff (~400) working in hazardous environments and exposed to noise, working at heights and in confined spaces as well as working with hazardous substances such as lead, mercury, naturally occurring arsenic, asbestos (change commences 1 January 2015) and other toxic/hazardous substances used by ActewAGL in the performance of work activities. Safe Work Australia's Hazardous Substances Information System details the substance/material and exposure limits.[439]
b. In April 2014 ACT WorkSafe released the, 'Temporary Traffic Management When Working on or Near Public Roads' guidance note, while the ACT Government approves the new Traffic Management on Work Sites Code of Practice (anticipated in 2014/15). ActewAGL Distribution has assessed the requirements in the guide and in December 2014 commenced the implementation of new and updated controls including a revised procedure for traffic management, signage, and

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[438] ACT *Work Health and Safety Regulation 2011,* Section 58

[439] Safe Work Australia, 2014, *Hazardous Substances Information System*, accessed on 16 January 2015, <http://hsis.safeworkaustralia.gov.au/>

training in traffic management blue card.[440]

c. Continued transition to High Risk Work Licences as per WHS Regulation, Part 4.5 [441]
d. The introduction of arc flash clothing into ActewAGL Distribution as per *AS/NZS 4863:2011, 'Safe working on or near low-voltage electrical installations and equipment'* which provides for a new level of requirements for electrical works and intends to meet Section 19 of the WHS Act. The new standards result in increased costs to roll out new arc-flash protective clothing and face shields in 2015/16.
e. The ACT Hazardous Manual Task Code of Practice (effective January 2012) is intended to eliminate or reduce muscular stress / strain injuries. In order to meet Section 19 of the WHS Act and the Hazardous Manual Task Code of Practice (effective January 2012), ActewAGL Distribution has and will continue the need to undertake detailed assessments of tools, plant and equipment and work practices to eliminate hazardous manual tasks or if this is not possible to reduce the risk so far as is reasonably practicable.
f. ActewAGL Distribution has assessed and identified controls relating to psychological, bullying and impairment of workers. One control is the identification of external support to educate ActewAGL Distribution employees about the impacts of psychological injuries and provide education regarding the early warning indicators. This is to ensure compliance with the ACT WHS Act's primary duty (Section 19) and Prevention of Bullying Code of Practice (effective May 2012) as well as addressing new regulatory obligation arising from the ACT and the *Fair Work Act 2009* anti-bullying amendments which come into effect on 1 January 2014.
g. Other than the specific changes identified above, ActewAGL Distribution is required to assess, review, write, consult and implement new management plans, procedures and safe work method statements to meet WHS Regulation and new Codes. Implementation involves the writing and delivery of new training to workers, including contractors and others that may be working on or near the distribution system. New Codes are detailed in Table 3.14 below. While the introduction of a number of these occurred in or before the 2012/13 base year, this serves to evidence the quantum of new Codes introduced since the changes in regulatory requirements.

[440] See Attachment C52, ACT WorkSafe, 2014, Temporary Traffic Management when working on or near public roads, March

[441] ACT *Work Health and Safety Regulation 2011*, Part 4.5

Table 3.14 Introduced Codes of Practice in the ACT

Code title	Approved & commenced by ACT Government	New / Revised ActewAGL Distribution Procedure
How to Manage Work Health and Safety Risks	January 2012	Revised in 2011/12
Confined Spaces	January 2012	Revised and implemented 2012/13
Construction Work Code of Practice ▪ Inclusion of construction work was a new requirement for ACT following the new WHS Regulation. The Decision Regulatory Impact Statement for National Harmonisation of Work Health and Safety Regulation [442] found that the regulatory impact would be higher in the ACT. ▪ New principal contractor duties under the WHS Regulation, particularly the trigger for principal construction duties set at $250,000.[443] ▪ Resulted in updating contractor management arrangements, policies, procedures and plans as well as any procedures relating to construction work, including the development of Safe Work Method Statements (SWM) in accordance with ACT WorkSafe requirements.	May 2012	New contractor management procedure released December 2014 Writing SWMs to new requirements to continue into 2014-19 regulatory control period.
Managing the Work Environment and Facilities This code requires assessments of work environments (working alone or in isolation) and facilities (bathrooms, kitchens, hot/cold water etc).	January 2012	New - Assessments and procedure completed November 2014. Identified controls still to be added to SWMs.
Managing Noise and Preventing Hearing Loss at Work	January 2012	New health procedure finalised

[442] See Attachment C48, Safe Work Australia, 2011, *Decision Regulation Impact Statement for National Harmonisation of Work Health and Safety Regulations and Codes of Practice*, November, page 154

[443] ACT *Work Health and Safety Regulation 2011,* Sections 289 to 293

Code title	Approved & commenced by ACT Government	New / Revised ActewAGL Distribution Procedure
Requirements relating to worker monitoring were incorporated into the new health surveillance and monitoring program as identified at point (b) above.		and approved January 2015 Noise management procedure released December 2014.
How to Prevent Falls at Workplaces	January 2012	Revised 2012/13
Preventing Falls in Housing Construction	August 2012	Revised procedure released January 2015
First Aid in the Workplace	August 2012	Revised procedure released July 2013.
Excavation Work The WHS Regulation specified additional controls in relation to excavation work, including the requirement to support the sides of trenches.[444] The Code provides further explanations and requirements for excavation and trenching work.	August 2012	Revised Excavation and Trenching procedure released December 2014
Managing Risks of Plant in the Workplace The WHS Regulation introduced new requirements for certain plant items and plant designs to be registered.[445]	August 2012	New - assessments to identify and register ActewAGL Distribution specified plant completed in 2012/13
Safe Design of Structures	August 2012	New methodology released in August 2013.
Welding Process	August 2012	To be reviewed in 14/15.
Demolition Work Prior to the commencement of the WHS Regulation the requirements for demolition work were largely contained in building laws. Under the WHS Regulation, the person conducting a business or undertaking	August 2012	New - Incorporated into the construction safety plans required. Procedure and templates released December 2014.

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[444] ACT *Work Health and Safety Regulation 2011*, Division 6.3.3

[445] ACT *Work Health and Safety Regulation 2011*, Sections 243 to 288D

Code title	Approved & commenced by ACT Government	New / Revised ActewAGL Distribution Procedure
proposing to undertake demolition work must notify the ACT WorkSafe regulator. [446]		
Managing Electrical Risks in the Workplace The WHS Regulation introduced a new requirement for electrical equipment used in a 'hostile environment' to be regularly inspected and tested by a competent person.[447] The WHS Regulation introduced a new requirement that any electrical risk associated with the supply of electricity to the electrical equipment through a socket outlet be minimised by the use of an appropriate Residual Current Device.[448]	August 2012	Revised procedures for inspection and testing as well as RCDs released in 12/13. Ongoing inspection and testing activities.
Tree Trimming and Removal Work – Crane Access Method	Impending	To be assessed
Safe Design, Manufacture, Import and Supply of Plant	Impending	To be assessed
Working in the Vicinity of Overhead and Underground Electrical Services	Impending	To be assessed
Scaffolds and Scaffolding Work	Impending	To be assessed
Industrial Lift Trucks	Impending	To be assessed
Cranes	Impending	To be assessed

Environment and public safety - bushfire mitigation

The AER's draft decision does not include a step change to account for changes in the ACT's bushfire mitigation standards or in ActewAGL's Bushfire Mitigation Strategy and Management Plan, stating:

[446] ACT *Work Health and Safety Regulation 2011*, Part 4.6

[447] ACT *Work Health and Safety Regulation 2011*, Division 4.7.3

[448] ACT *Work Health and Safety Regulation 2011*, Sections 164 and 165

Complying with bushfire mitigation standards is a normal obligation of providing network services. ActewAGL has not presented us with any evidence that likely changes in standards would be more onerous than existing standards.[449]

ActewAGL Distribution maintains that revisions to the Strategic Bushfire Management Plan for the ACT as well as changes in bushfire risk assessment and management following bushfires and resulting litigation in other states has led to significant changes in ActewAGL Distribution's regulatory obligations and the strategies required to prevent and mitigate fires, and develop plans to protect and improve network resilience, security and safety.

ActewAGL Distribution has legal obligations under a number of legal instruments to provide a safe electricity network within its area of operations. These instruments include the *Emergencies Act 2004* and associated subordinate legislation, the ACT *Utilities ACT 2000*, the *Work Health and Safety Act 2011* (WHS Act) and Common Law requirements in the ACT. Under the ACT *Utilities Act 2000* ActewAGL Distribution has specific requirements to provide a safe network to the community and workers. Under the WHS Act, ActewAGL Distribution as a PCBU has obligations as per the primary duty of care[450] regarding its assets, business and work practices. In addition, under Common Law within the ACT, there is a common law duty for ActewAGL to exercise its powers where it is, or should be, aware of interference with its network. Failure to do so may leave ActewAGL exposed to liability for negligence as opposed to other jurisdictions. Importantly the ACT Common Law provisions are uncapped in contrast with other jurisdictions. Furthermore, the WHS Act has strengthened obligations with regards to site preservation requirements that would carry over to any fire that may have been caused by assets managed by ActewAGL Distribution. In combination, the WHS Act has changed the operating environment in a way that was not understood previously, nor costed or incorporated into base year costing.

The ACT Strategic Bushfire Management Plan (SBMP) Version 3 2014[451] is an instrument that is a subordinate law to the *Emergencies Act 2004* and was prepared by the ACT Emergency Services Agency to meet the requirements of Section 80 of the *Emergencies Services Act 2004*. As such, the SBMP addresses all bushfire management elements as required by Section 74 of the *Emergencies Services Act 2004*.

[449] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-150

[450] ACT *Work Health and Safety Act 2011,* Section 19

[451] See Attachment C53, ACT Emergency Services Agency, *The ACT Strategic Bushfire Management Plan, 2014-2017*

An over-arching principle of bushfire management in the ACT is that of shared responsibility between the ACT Government and the community for mitigating bushfire risk. The SBMP Version 3, 2014 was released and has resulted in the requirement to make material changes to planning and operations for ActewAGL Distribution. The updated SBMP explicitly requires that ActewAGL Distribution participates in a proactive plan. The ACT SBMP Version 3, 2014 updates the previous SBMP for the ACT, which is Version 2 dated October 2009. Version 2 had no specific reference or obligations for ActewAGL Distribution or its past entities. There was no regulatory requirement to have a Bushfire Operational Plan or liaise with the ESA in any way. The obligations changed markedly in Version 3 2014, with a specific reference in Schedule 2 for ActewAGL to have a Bushfire Operations Plan in designated Bushfire Prone Areas approved by the ESA. Costs incurred in this step change directly relate to the Clause 6.5.6 (a) (2) of the Rules and were not included in the base year as the regulations subsequently changed.

The 2009 Victorian Bushfires Royal Commission Final Report, [452] provided 67 recommendations targeted at the Commonwealth, the State, and in specific cases (recommendations 27 – 33 inclusive) Victorian DNSPs.

As a prudent operator, ActewAGL Distribution has commenced addressing the recommendations and requires additional opex within the 2014-19 regulatory control period to continue to undertake risk assessments and update documentation. ActewAGL Distribution has formed the opinion that when the obligations under the *Utilities Act 2000*, the *WHS Act 2011*, and the ACT Common Law provisions are analysed together, there is heightened risk of ActewAGL Distribution being deemed to be negligent by not adopting the recommendations. In particular improved knowledge specific to bushfire risk mitigation in the industry has led to heightened assessments and the identification of risk by ActewAGL Distribution, which requires additional expenditure to maintain the safety, reliability and security of the distribution system through the supply of standard control services. Additionally it should be noted that a number of other DNSPs have not or are in the process of adopting these recommendations and hence comparison with other DNSPs that suggests these recommendations should be captured in base year opex for a prudent operator is not appropriate.

During the previous 2009–2014 period, ActewAGL Distribution commissioned external specialists to undertake an initial analysis aimed at developing a better understanding of bushfire risk across the ACT associated with the distribution network. Notably similar work was conducted by the Victorian Government at its cost, rather than being paid for by Victorian DNSPs. Costs included in this step change are in response to the changes to the ACT SBMP, including analysis,

[452] See Attachment C54, Teague AO, B., McLeod AM, R. and Pascoe AM, S., 2010, *2009 Victorian Bushfires Royal Commission Final Report Summary*, July

consultation and implementation, and compliance. Neither the requirement to have an approved Plan, nor the funding existed in the base year. In addition understanding the risk to operations in a formal and very specific asset by asset, risk by risk sense also forms a part of the primary duty of care under the WHS Act.

Recent bushfires including Kilmore and Murrindindi in Victoria as well as the Blue Mountains in NSW have also contributed to a greater focus on bushfire risk and bushfire mitigation. Of concern are areas where asset failure caused a fire or where trees outside the clearance zones caused fires. The Powerline Bushfire Safety Taskforce[453] summarised the Victorian fires and the operational failure. This has led ActewAGL Distribution to consider additional risk mitigation required to maintain the safety of the distribution system and keep the system secure from liability of harm, injury, danger or other risk. ActewAGL Distribution requires specialist assistance to identify opportunities to improve asset resilience against identified risks. ActewAGL Distribution has in the past used the run to failure model with particular relevance to underground cable faults and potheads on the low voltage network. ActewAGL Distribution recognises the significance of the consequences of failure in rural and potential bushfire areas and requires expertise to assist in efficient targeting of asset replacement. ActewAGL Distribution considers that a run to failure model is not a safe (does not allow for ActewAGL Distribution duties holders to discharge their WHS duties or meet the risk management duty) or efficient model when the outcomes of that failure are significant community and worker safety, as well as environmental destruction.

The recent bushfires and subsequent inquiries have also highlighted inadequacies in existing industry bushfire mitigation standards. This has placed additional pressure on ActewAGL Distribution to revise risk assessments and review bushfire mitigation strategies. Expenditure identified in the recommended opex step change is for the engagement of expert independent consultants to undertake an assessment and make recommendations on the most cost effective areas to target to reduce bushfire risk and improve resilience including planning, asset and response perspectives.

The 2014 changes to the SBMP result in increased costs to update relevant policies and procedures for managing bushfire readiness, and to implement procedures for reducing the bushfire risk from network assets. This will include a review and update of the ActewAGL Distribution Bushfire Mitigation Strategy and Management Plan to ensure it aligns with the current environment. The review of changes to ActewAGL Distribution policies and procedures will be externally audited to ensure legislative requirements are being met and they reflect best practice. These activities and costs are listed in Table 3.15.

[453] See Attachment C55, Orton, T. (Chair), 2011, *Powerline Bushfire Safety Taskforce: Final Report*, September

Asbestos and unexploded ordnance

When the new WHS Act commenced on 1 January 2012, the ACT primarily had two pieces of legislation covering asbestos management, being the *Dangerous Substances Act 2004* and the *Work Health and Safety Act 2011*. This created a level of confusion and additional effort when it came to the notification of asbestos related incidents as both pieces of legislation required separate notification, including the additional notification to the ACT Environmental Protection Agency.

Hazardous chemicals including lead, asbestos and major hazard facilities which comprise Chapters 7, 8 and 9 respectively in the WHS Regulation were not included as the ACT Government decided that these were to continue to be regulated under the *Dangerous Substances Act 2004* and associated Regulations pending a review in 2012.[454] Some changes and points of clarification were released in late 2014, after the regulatory proposal was submitted, which resulted in ActewAGL Distribution reviews and updates to related procedures and practices.

The WHS Regulation, Section 445 was amended in 2014 and required specific occupations, who may be working with or exposed to asbestos, to complete accredited 'Asbestos Awareness' training only with ACT WorkSafe accredited training providers. A duty was placed on persons conducting a business or undertaking (PCBU) to ensure identified workers had completed the training by 30 September 2014. This change was an additional cost to ActewAGL Distribution in changing asbestos procedures and providing the necessary training to engineers, field workers, managers and supervisors and specifically is covered by the National Electricity Rules 6.5.6 (a) (2) and was not foreseeable.

A further legislative change has occurred since the regulatory proposal was submitted relating to asbestos management. On 25 November 2014 the *Dangerous Substances (Asbestos Safety Reform) Amendment Bill 2014* was passed in the ACT Legislative Assembly paving the way for the adoption of the national model asbestos laws. The Bill and Amendment Regulation, including two supporting Codes of Practice are to commence on 1 January 2015. One significant change in the law is the removal of the 10 square metre exemption which will mean that any asbestos identified can only be removed by licenced asbestos removalists (must hold a Class A or B removalist license). For ActewAGL Distribution this means that when excavating to replace poles or trench to lay underground assets, any asbestos found will result in costs associated with testing, a licensed asbestos removalist, air monitoring, tipping fees and clearance certificates.

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[454] ACT WorkSafe, 2014, Work Health and Safety Legislation, accessed on 16 January 2015, <http://www.worksafe.act.gov.au/page/view/2798>

The base year included incidental discovery, handling, and removal of asbestos under the old legislation however this recent change imposes additional costs.

Unanticipated costs associated with the standard operating environment are a component of expenditure in the base year. However the ACT Government has changed strategies to release / rezone land previously zoned as industrial to high density residential developments. This strategy has led to unanticipated costs associated with significant asbestos discoveries (and other issues such as hydrocarbon plumes) in brownfield developments during the current period, and have been as high as $50,000 per incident from discovery, reporting, registration to disposal. ActewAGL Distribution analysis has identified that the incidences of unexpected asbestos discoveries will continue to increase over the 2014-19 regulatory control period as the undergrounding of electrical assets continues in re-development areas. Importantly this is not covered by the development cost. Developers work within the property boundary to ameliorate any known or discovered issues and the land purchase price theoretically accounts for this cost. However ActewAGL Distribution operates outside the property boundary incurring the same costs without the ability to charge the developer. Since September 2013 unanticipated asbestos discoveries have occurred once every 2.5 months. Additional opex is required to risk assess, remove / mitigate and dispose of unanticipated asbestos (and other) finds in re–development areas. ActewAGL Distribution requires this step change expenditure to maintain the ongoing safety of the distribution network. Base opex is inadequate to keep the distribution system safe by managing the risk of harm, injury or danger related to asbestos discovery and management.

A further unanticipated cost associated with the ACT Government changing planning strategies, is the impact of unexploded ordnance. The ACT Government has indicated that the Molonglo area will be rezoned and developed for urban residential usage. This change is beyond ActewAGL Distribution’s control and outside current business operations. This Molonglo area is known to have been used as an artillery range in the past with known unexploded ordnance having been found. There is a clear change in risk level leading to a material change in costs to meet existing legislation. Additional opex is required over the 2014-19 regulatory control period to conduct a risk assessment on any work associated with the Molonglo area and update procedures and asset maintenance documentation. Work has not commenced in the Molonglo area to date, and as a result there were no costs in the base year. Under the *WHS Act 2011* primary duty of care ActewAGL Distribution must address the risk associated with sending our staff or contractors into an area with a known hazard without any specific risk controls.

ActewAGL Distribution must maintain a database of non-residential asbestos sites as part of the asset register under Section 327 of the *Dangerous Substances (General) Regulation*. Although this database was developed in April 2010, it must now be maintained by a Class A Licenced Asbestos Assessor. ActewAGL Distribution must comply with legislation and outsource this requirement. All sites are reassessed independently and on an annual basis.

These activities and their costs are provided in Table 3.15.

Climate change resilience

The AER draft decision does not allow a step change for climate change resilience, stating:

ActewAGL did not link it to a regulatory change nor did it specify or quantify the costs of this project. In any case, ActewAGL has been aware about the risks of climate change for some time. We would expect that as a prudent business it would have begun considering how these risks could impact on its business.[455]

Although ActewAGL Distribution has been aware of climate change risks and has begun considering these risks on the business, the base year did not include adequate expenditure to undertake a targeted risk assessment and investigation to identify and quantify the cost and extent of work needed to ensure climate change issues are factored into efficient investment in and operation of electricity services for the long term interests of consumers.

Existing climate vulnerabilities highlight the need for businesses, including utilities, to be able to respond to climatic variability that may affect their operations. This requires the capacity to make decisions that are informed by a sound understanding and a commonly agreed set of parameters of projected climate change and its impacts. In responses to other DNSPs, the AER has broadly indicated that the adopted models are not fit for short term forecasting and the claimed effects have been rejected. In addition the AER indicates that the modelling does not establish with certainty that any particular modelled scenario has a higher or lower probability of eventuating.[456] To remedy the challenge of model certainty the Energy Networks Association (ENA) in consultation with the AER has produced a climate risk and resilience manual for the energy network sector which will aid in providing a consistent approach by all network service providers in managing climate risk and resilience across core network activities.

For ActewAGL Distribution, understanding how and when to adapt to the increased risk profile arising from climate change will incur additional costs as it will require a combination of technical knowledge of the physical impact on the network assets as well as analysis of the potential future impact of climatic conditions over the assets lifespan. By using industry agreed processes, ActewAGL Distribution can undertake a probabilistic risk assessment to understand the extent of the risk of environmental factors beyond our control, and how ActewAGL Distribution might specifically address threats to specific assets. These decision criteria will enable synergies between asset maintenance, asset resilience improvement and bushfire mitigation.

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[455] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-151

[456] See Attachment C56, AER, 2010, *Final Decision, Victorian electricity distribution network service providers, Distribution Determination 2011-2015*, October, page 408

Summary of activities and costs

The opex step change is $2.8 million, which includes expenditure for a number of additional activities requiring specialist input such health and safety professionals, risk assessment, asbestos and unexploded ordnance specialists; and health practitioners enlisted to carry out health monitoring and surveillance checks.

These measures are imperative to address the potential risk (and consequential cost) outcomes of serious harm to workers and the public as well as damage to network distribution assets. Additionally, the step change allows ActewAGL Distribution to discharge various WHS Act, bushfire and environmental duties and obligations.

These skills are not core to ActewAGL Distribution's internal staff. Therefore it is not considered cost effective for the initiatives outlined in this report to be delivered or substituted with internal resources. Significant programs requiring additional operating expenditure for external resources are detailed in Table 3.15 [cic] and summarised below:

- Improve the health and wellbeing of ActewAGL Distribution employees and reduce the incidence of long term injury through 'Project Substance', providing ongoing health monitoring commencing in 2015/16 and expecting a trend down in compensation costs in the medium term.
- Increase awareness training on sprains/strains and injuries to minimise injury to ActewAGL Distribution employees in the course of their work. Vehicle incident training and management to minimise injuries as a result of vehicular incidents, reduce damage to the ActewAGL fleet and potentially reduce fleet insurance premiums.
- Delivery of education to employees on the early warning signs of psychological injury enabling them to seek timely support and reduce future incidents.
- Update the Bushfire Mitigation Strategy and Management Plan in 2015/16 to ensure it is consistent with and complementary to the ACT Government's revised Strategic Bushfire Management Plan. This will ensure legal obligations are met and improve ActewAGL Distribution's bushfire mitigation activities beyond the current inadequate industry standards to further reduce the likelihood and consequences of bushfires in the ACT and reduce risk to the community and the reliability, safety and security of ActewAGL Distribution's network.
- Address unplanned safety events from asbestos dumps and unexploded ordinance resulting from new land releases in the ACT to reduce safety risks to the public and ActewAGL Distribution personnel during next regulatory control period.
- Develop strategy on business risk, continuity and resilience to climate change in response to the Electricity Networks Association (ENA) manual on climate change. This activity requires specialised external consulting resources.

Table 3.15 EHSQ step change activities and costs

($ million, 2013/14)	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Health - Injury prevention programs	**0.28**	**0.20**	**0.23**	**0.18**	**0.17**	**1.06**
1. Hazardous Substances Health monitoring	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2. Workplace assessment - muscular strain & sprain	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3. Leadership training and communication plan for safety cultural change	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4. Pre-employment and exit medical tests	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5. Specialised MV handling & training	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6. Psychological Injuries - Awareness, treatment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7. Workplace wellness & Incorporation of Anti bullying legislation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8. Return to Work Rehabilitation and work place assessment - contractors	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Environment & Public Safety - Bushfire Mitigation	**0.13**	**0.13**	**0.02**	**0.04**	**0.01**	**0.32**
1. SBMP review, consultation and amendments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2. SBMP - Internal changes to Processes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3. SBMP - Changes to Policies (Maintenance on high Bushfire risk days)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4. Review of ActewAGL's Bushfire mitigation strategy and Management Plan	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5. Independent review of Bushfire risk	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Safety - Unplanned Events	**0.25**	**0.24**	**0.27**	**0.29**	**0.24**	**1.28**
1. Additional Asbestos discovery, registering event and disposal of asbestos.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2. Specialist Environmental Consultant - Annual Asbestos Survey	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3. Unexploded Ordinances	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4. Risk Assessment of Area - Specialist Consultant for unexploded ordinances	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6. Implement Risk Mitigation strategies proposed by the Specialist Consultant.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Climate risk and Resilience	**0.01**	**0.11**	**0.03**	**0.03**	**-**	**0.19**
1.Business Risk, Continuity & Resilience to Climate Change manual developed by the ENA - Specialist Input	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total step change	**0.67**	**0.67**	**0.54**	**0.54**	**0.41**	**2.83**

It is not feasible to accurately quantify benefits resulting from implementing this option as these are predominantly risk-based, however ActewAGL Distribution anticipates the following benefits from the activities included in this step change:

- Compliance with legislative and regulatory duties and obligations, resulting in reduced risks of charges, fines and court proceedings against ActewAGL Distribution, AER and their officers
- Reduced incidence of long term injury to ActewAGL Distribution employees and contractors and related injury management expenditure
- Improved incident investigation and management
- Improved procedures, safe work method statements and practices
- Reduced number of motor vehicle incidents, resulting in reduced costs associated with injury to employees, damage to fleet vehicles and potential reductions in fleet insurance premiums
- Reduced incidence and severity of psychological injury
- Reduced likelihood and consequences of bushfires in the ACT and reduced risk to the community as well as to the reliability, safety and security of ActewAGL Distribution's network
- Improved ability to address unplanned safety events from asbestos dumps and unexploded ordinance and consequent reduction in safety risks to the public and ActewAGL Distribution personnel.
- Avoided cost of potential non-compliance action against ActewAGL Distribution.
- Avoided/Reduced liability due to potential incidents where ActewAGL Distribution assets initiate a bushfire.

3.6.3.2 *Regulatory compliance and strategy step change*

Overview

The AER's draft decision includes a step change of only $1.4 million of the $8.6 million proposed by ActewAGL Distribution for additional expenditure related to regulatory compliance and strategy.[457]

ActewAGL Distribution maintains that this step change in required to achieve the opex objectives and reflects the opex criteria. The increase in costs from base year opex is driven by the increasing *volume* and *complexity* of compliance and regulatory requirements and associated documentation and process burden for ActewAGL Distribution as a result of the introduction of new obligations.

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[457] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-151

The costs included in this step change are for engagement of specialist consultants, auditors and additional highly skilled internal resources, including two regulatory specialists, one consumer engagement specialist, and one distribution strategy specialist. These costs are detailed in Table 3.16 below.

Table 3.16 Regulatory compliance and strategy step change costs

($million, 2013/14)	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Regulatory reporting	0.31	0.31	0.26	0.96	1.51	3.33
National Energy Customer Framework (NECF)	0.07	0.07	0.07	0.05	0.05	0.30
National Planning and Expansion Framework (NPEF)	0.21	0.19	0.16	0.14	0.14	0.84
Consumer engagement	0.31	0.31	0.27	0.38	0.29	1.56
AEMC Network Pricing Arrangements 2014	-	0.02	0.12	-	-	0.14
Strategic review of network tariffs	1.29	0.18	0.13	0.59	0.13	2.31
AEMC Connection of Embedded Generation	0.04	0.04	0.02	-	-	0.10
Total	**2.22**	**1.11**	**1.03**	**2.11**	**2.11**	**8.58**

Increased regulatory reporting

The AER's draft decision includes $1.0 million of the $3.3 million proposed by ActewAGL Distribution for increased regulatory reporting requirements.[458] The AER's explanation of its draft decision is as follows:

- *We have included the increased regulatory reporting costs of submitting the benchmarking, category analysis and reset RINS. The level of detail we requested in the benchmarking and category analysis RINs is greater than we have requested previously and the cost of submitting reset RINs is not included in the efficient base level of opex.*
- *We have not included the costs of completing category analysis RINs in 2017–18 as the information will be captured in the costs of completing a reset RIN.*

[458] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-152

- *We have not included the costs of completing annual reporting RINs. They are not a new regulatory obligation and these costs are already included in the efficient base level of opex.*
- *We pro rata the consultancy costs accordingly.*
- *We substituted lower labour costs than ActewAGL used in its estimate of the cost of increased regulatory reporting. ActewAGL's FTE cost estimates are based on the cost of an engineer at $232,500 per annum. However, we consider regulatory reporting can be done by a less qualified employee. We substituted ActewAGL's most recent average labour cost of $180,000, as reported in its category analysis RIN data.* [459]

ActewAGL Distribution considers the new RIN requirements call for an increased level of granularity in reporting of financial and non-financial information which has driven a material increase in costs associated with coherent regulatory reporting for the 2014-19 period above what has been allowed for by the AER. The new RIN requirements include economic benchmarking, category analysis benchmarking, and are in addition to the annual RIN and reset RIN requirements.

Efficient collecting, collating and publishing of RIN data requires more experienced employees than average which results in a higher average labour cost. Adjustments for less experienced staff would require a corresponding increase in the number of staff to compensate for the decreased productivity.

Considerable additional support from high level specialist consultants for both financial and non-financial information is also required. Additionally, the RINs require historical values to be independently in accordance with Australian Auditing Standards.

AER - Regulatory Information Notices - category analysis and economic benchmarking

The requirement to complete a category analysis RIN and economic benchmarking RIN is new. The completion of these RINs was labour intensive and required significant external consultancy to complete in the timeframe set by the AER. While this work is expected to be refined over time, ActewAGL Distribution considers it most efficient to undertake much of this work internally. For the 2013/14 economic, category analysis and annual RIN returns the total internal labour effort was in excess of 1,000 hours. RIN returns require periodic engagement of specialist technical consultants as well as auditors.

AER – 5 yearly Reset RIN

[459] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-152

The level of detail required to complete the reset RIN is voluminous and complex. This is a recurrent expenditure for each regulatory control period and requires a high volume of work to be undertaken in years 4 and 5 leading up to the next regulatory reset period. The ActewAGL Distribution 2014-19 Reset RIN incurred an estimated 4,000 internal labour hours along with additional support from specialist consultants.

National Energy Customer Framework (NECF)

The AER's draft decision includes a step change of $0.2 million for the implementation of customer connection charges, but not quarterly NECF breach reporting.[460]

In not including breach reporting, the AER notes:

We have not included this component of the step change in our opex forecast because we do not consider a prudent service provider would assume it is going to breach the NECF, and hence the law, twice a year. [461]

While ActewAGL Distribution's target is to have no NECF breaches, a minimal annual budget provision totalling $0.1 million across the period has been included in the proposed step change to cover technical and legal investigation assessment of potential breaches, as ActewAGL Distribution's experience to date has been that the handling of Type 1 breaches has been very labour intensive in the reporting to the AER and the investigation process.

National Planning and Expansion Framework 2012(NPEF)

ActewAGL Distribution's regulatory proposal included $0.8 million in this step change related to the NPEF including costs:

- publish a distribution annual planning report (DAPR)
- investigate demand side solutions
- participate in the service target performance incentive scheme (STPIS).

The AER's draft decision does not allow these costs because it considered these costs should already be included in the efficient base level of opex.[462]

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[460] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-152

[461] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-153

[462] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-153

ActewAGL Distribution considers the new obligations imposed by the NPEF were significant and have led to ongoing internal costs that were not incurred in the base year. These new obligations include the annual review and publishing of the DAPR, the annual review and publishing of the Demand Side Engagement Strategy and its internal implementation within ActewAGL Distribution, and the requirement for RIT (D) consultation.

Distribution Annual Planning Report (DAPR)

ActewAGL Distribution was required to publish the DAPR for the first time in 2013/14 as required by the AER. The output was minimal in content compared to other DNSPs. The on-going annual publication requires additional resources to bring the report standard in line with that of its industry peers. The estimated annual allocation is 300 to 500 hours to complete the report and involves significant upstream technical compilation and collection of data, drafting of the report and quality assurance.

Participation in the Service Target Performance Incentive Scheme (STPIS)

ActewAGL Distribution is required to monitor daily reports of compliance and this has significantly increased the level of monitoring for single premise outages. Additional reporting on the call centre – to record per cent of calls responded within 30 seconds. The STPIS on the LV network commencing in 2015/16 will require significant increase in volume of STPIS reporting. Similar STPIS reporting exists, however the format of reporting and the additional LV networks and reporting of single premise outages makes this a significant step change.

Demand side solutions and engagement

The resources invested in demand side solution investigations will increase with the range of credible demand side solutions that needs to be investigated, as well as engagement with specialists. Demand side solutions also require closer engagement with customers for implementation.

Consumer engagement

ActewAGL Distribution's regulatory proposal included $1.6 million in this step change for additional consumer engagement. The AER did not allow for this step change in its draft decision, stating that:

Changes to the NER in late 2012 require service providers to describe how they have engaged with consumers, and how they have sought to address any relevant concerns identified as a result of that engagement. ActewAGL was required to present this information in an overview report with its regulatory proposal. Notwithstanding the rule change, we would expect a prudent service provider would already have programs in place to engage with consumers. The new NER requirement to *address consumers' concerns in its regulatory proposal would not lead to a material increase in opex and could be funded through the efficient base level of opex of an efficient and prudent service provider.*[463]

Following the rule change, the AER released a Consumer engagement guideline, which outlines its expectations of how electricity and gas distributors are to engage with consumers. The AER's consumer engagement guideline notes:

> *At present, most service providers undertake some form of consumer engagement. However, we are aware of significant variations in consumer engagement:*
>
> - *between distribution and transmission service providers across the gas and electricity sector*
> - *within each group of service providers (for example, between distribution electricity businesses)*
> - *by a single service provider over time …*
>
> *Implemented properly, the guideline may require most service providers to significantly change how they run their businesses. We expect service providers, helped by the guideline, to develop and implement strategies for consumer engagement to occur in a more systematic and strategic way. Service providers should seek to understand and address issues of significance to the business and its consumers. Over time, we expect service providers to embed consumer engagement in their businesses.*[464]

While ActewAGL Distribution has historically performed consumer engagement activities, it considers that this rule change and guideline has placed a new regulatory obligation as to the extent of consumer engagement and reporting on engagement to the AER and CCP and as noted by the AER, the level of existing engagement varies significantly. ActewAGL Distribution's proposal sets out a clear path for formalising a customer engagement strategy for the future.

ActewAGL Distribution's *Consumer Engagement Strategy* is proposed to be implemented over the 2014-19 regulatory control period. Stage 1 has commenced in 2014/15 and it is anticipated that one full time staff and external specialist skills will be required to successfully co-ordinate existing consumer engagement activities and the roll-out of proposed expanded activities. These costs are additional to consumer engagement activities undertaken in the base year. Whilst ActewAGL Distribution has previously undertaken extensive engagement through sophisticated willingness to pay studies as discussed in Chapter 1, no study was undertaken in the base year.

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[463] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-154

[464] See Attachment C57, AER, 2013, *Explanatory Statement, Customer Engagement Guideline for Network Service Providers,* October, pages 7 to 8

The major planned consumer engagement activities are co-ordination and preparation for the ActewAGL Distribution Energy Consumer Reference Council (ECRC), monthly meetings for 2015 then quarterly meetings long term; consumer analysis involving customer focus surveys and work groups; liaison with major customers; implementation of staff training to move towards a more customer centric organisational culture; and website adaption to encompass consumer engagement. These activities are discussed further in section 1.3 of this revised regulatory proposal. ActewAGL Distribution considers these consumer activities will deliver significant benefits to consumers, including:

- more comprehensive, relevant and timely information on the work of ActewAGL Distribution and its potential impacts;
- increased and more regular opportunities to provide input into decision making on efficient investment and operation of ActewAGL Distribution's services that will serve the long term interested of consumers; and
- better understanding of what impacts on energy bills and therefore more transparency around ActewAGL Distribution's decision-making and the impacts of regulatory activities and processes.

AEMC network pricing arrangements 2014 and Review of network tariffs

The AER's draft decision includes $0.1 million as proposed by ActewAGL Distribution for expenditure related to the AEMC rule change regarding network pricing arrangements.

The AER's draft decision does not include $2.4 million as proposed by ActewAGL Distribution for additional expenditure related to reviewing its network tariff strategy, and notes:

…we do not consider a step change is needed for an internal management decision about how better to meet pricing obligations. [465]

ActewAGL Distribution contends that this step change is required for ActewAGL Distribution to achieve the opex objectives. The review of network tariffs is required to address the AEMC's substantial changes to requirements relating to network pricing arrangements, which have created substantial change that requires ActewAGL Distribution to review its network tariffs and meet on-going requirements..

The costs included in this step change are for the following activities:

- Detailed studies to identify long run marginal costs at the individual tariff level

[465] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-154

- Development of a new pricing model to accommodate new tariffs
- AER approved connection charge policy with internal applications and charging manuals
- Consultation on the Tariff Structure Statement
- Preparation of the Tariff Structure Statement

The large increase in consultant costs included in this step change is due to insufficient internal resource levels, as appropriately skilled internal resources will be required for other existing regulatory and pricing activities. Further, a review of network pricing reports released by other DNSPs indicated that several consultancy firms have expertise and experience in network pricing reform, which could be drawn on efficiently for ActewAGL Distribution's review. This review will benefit consumers through more cost reflective tariffs that are fairer and encourage more efficient energy supply and use.

AEMC connection of embedded generation

The AER's draft decision includes $0.1 million as proposed by ActewAGL Distribution for expenditure related to the AEMC rule change regarding connection of embedded generation.

3.6.3.3 *Technical standards, safe work practices and contractor management*

The AER's draft decision does not include step changes for additional expenditure related to technical standards, safe work practices or contractor management as it did not consider any of these step changes arise from a new regulatory obligation.[466]

Technical standards

The AER did not allow a step change of $1.5 million for additional technical standards expenditure, stating:

The updated Management of Electricity Networks Assets Code is not a new regulatory obligation and we are not satisfied it has imposed a materially heavier burden on ActewAGL than previously. We consider the costs of ActewAGL complying with updated industry standards and updating its five year technical standards plan should be met from the efficient base level of opex.[467]

[466] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-155

[467] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-155

ActewAGL Distribution maintains that this step change in required to achieve the opex objectives and reflects the opex criteria. Specifically this step change is required to meet the requirements of the updated *Management of Electricity Networks Assets Code* under the *Utilities Act 2000,* as well as changes to other regulatory obligations relating to safety and technical standards. The updated Code has set the compliance with applicable Australian and International standards as a mandated minimum. This requires ActewAGL Distribution to revisit all existing standards and guidelines to ensure minimum safety standards are provided for the design, construction, operation and maintenance of the electricity network. ActewAGL Distribution has detailed the requirement for this step change in its regulatory proposal[468] and further detail was provided in response to an information request from the AER.[469]

Safe work practices

The AER did not allow a step change of $3.5 million for an electrical safety documentation team on the basis that the regulatory obligations driving the need for this team are not new.[470]

ActewAGL Distribution maintains that this step change in required to achieve the opex objectives and reflects the opex criteria. Under its technical and safety regulatory obligations including the WHS Act 2011 and codes of practice under the Utilities Act 2000 ActewAGL Distribution must maintain electrical safety documentation that is consistent with current codes of practice and the WHS Act 2011. It also has an obligation to eliminate or minimise identified risks to workers and other persons to the extent that is reasonably practicable. These are discussed further in Section 3.6.3.1. ActewAGL Distribution contends that costs to meet these new regulatory obligations could not be met with base opex. ActewAGL Distribution has detailed the requirement for this step change in its regulatory proposal.[471]

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[468] ActewAGL, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period*, *Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), page 229 and Attachment B10

[469] ActewAGL, 2014, *Response to OPEX Step Change AER Questions*, 24 July

[470] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-155

[471] ActewAGL, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period*, *Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), page 229 and Attachment B10

Contractor management

The AER did not allow a step change of $3.1 million for additional contractor management expenditure, stating:

ActewAGL's duty of care to contractors has not changed and the requirement to complete a Safe Work Method Statement has not changed for either employers or principal contractors from those adopted under the Work Safety Act 2008. [472]

ActewAGL Distribution maintains that this step change in required to achieve the opex objectives and reflects the opex criteria.

This step change is required for additional resources to manage contracts and has primarily been driven by new obligations under the *WHS Act* which are required to be incorporated into ActewAGL Distribution's existing and new contracts. The *WHS Act* places more obligations and responsibility on ActewAGL Distribution, specifically in the area of contractor management relative to the repealed, ACT OHS legislation. Additionally, OHSAS 18001:2007 aims to assist organisations in managing and controlling their health and safety risks and improving their Occupation Health and Safety performance. Failure to adequately address safety concerns in respect of contractor management, particularly those issues relating to health and safety, may result in OHSAS 18001:2007 certification being removed. This would give rise to a number of safety and legal issues as certification with this standard ensures ActewAGL Distribution has a demonstrably sound occupational health and safety performance.

As explained in Section 3.6.3.1, responding to new requirement under the *WHS Act* in terms of assessing the impact on the organisation and responding to legislative changes requires iterative consultation. Once the issues are identified and agreed, there is a need to identify measures and progressively implement changes. Therefore, the incremental cost of reviewing contract management in light of the *WHS Act 2011* was not accounted for in the 2012/13 base year. This step change will enable resources to focus on implementing these changes and will ensure ActewAGL Distribution meets its regulatory obligations with respect to minimising risk to the health and safety of its contractors and the public through improved oversight of contractor safety and performance management arrangements, including review, monitoring and

[472] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-155

evaluation of existing and future contracts. Further detail of the requirement for this step change is provided in ActewAGL Distribution's regulatory proposal.[473]

3.6.3.4 *Network operations and call centre and network OT support*

The AER's draft decision does not accept ActewAGL Distribution's proposed step changes for neither network operations and call centre opex nor network OT support opex. The AER does not accept ActewAGL Distribution's claim that these step changes are required to meet NECF and STPIS requirements as these are not new regulatory obligations. It also considers efficient discretionary changes in inputs should normally have a net negative impact on expenditure,[474] stating:

We expect that a business would only invest in IT where the benefits of that investment are expected to outweigh the costs. The expectation of future benefits should be sufficient incentive to undertake this investment and no increase in opex is needed.[475]

ActewAGL Distribution maintains that these step changes of $2.1 million for Network Operations and Call Centre and $4.8 million for Network OT Support are required to achieve the opex objectives and reflects the opex criteria. These step changes are driven by the need to upgrade network system operating and reporting capability following the OSRP and to meet the new requirements of the NECF customer service standards and STPIS.

The completion of the OSRP will enable further necessary OT works planned for the 2014–2019 regulatory control period to meet the needs of ActewAGL Distribution's network by ensuring safety, network reliability, quality, and customer service standards are maintained. As a result of these network OT investments, greater operational support is required to operate and support these systems as well as to support the transition into future needs.

ActewAGL is participating in reporting statistics for the STPIS for the first time in 2015/16. The granularity of information requested and the frequency of reporting to the AER for STPIS has increased since the base year.

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[473] ActewAGL, 2014, ActewAGL, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period, Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), page 229 and Attachment B10

[474] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-156

[475] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-148

Additionally, the introduction of the NECF has required a number of changes within ActewAGL. As the AER notes, a cost pass through of $1.9 million was approved in January 2013 for costs incurred to establish and set up the customer framework.[476] However, the costs included and accepted in this pass through related to implementation of the NECF only, and were not for on-going additional costs required as a result of the introduction of the NECF. This step change includes on-going costs that will be incurred during the 2014-19 regulatory control period to meet the system reporting requirements of the NECF. ActewAGL Distribution has detailed the need for this step change in its regulatory proposal[477] and further detail was provided in response to an information request from the AER.[478]

3.6.3.5 *Corporate services (including capitalisation of corporate services)*

Overview

The AER's draft decision did not include any opex forecast for corporate services step changes. The proposed step changes were excluded on the basis that they were not driven by new regulatory obligations or other changes in ActewAGL's operating environment beyond its control.[479]

ActewAGL Distribution's regulatory proposal included a $10.1 million forecast over the period for Corporate Services step changes, however in responding to a related question from the AER, an error in ActewAGL Distribution's base year adjustments was discovered. This led to ActewAGL Distribution reporting a revised step change amount of an additional $7.6 miilion to the AER for both the corporate services charge and capitalisation of corporate services charge step changes.

ActewAGL Distribution's revised corporate services step changes are provided in Table 3.17 below.

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[476] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-156

[477] ActewAGL, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period, Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), page 230 and Attachment B10

[478] ActewAGL, 2014, *Response to OPEX Step Change AER Questions*, 24 July

[479] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-156

Table 3.17 Revised corporate services charge step change

($million, 2013/14)	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Salaries & wages escalation	0.5	1.0	1.3	1.4	1.5	5.9
Software licence escalation	0.3	0.3	0.3	0.3	0.3	1.5
Opex related to CSRP	0.1	0.1	0.1	0.1	0.1	0.5
Ongoing opex related to capex programs	0.3	0.3	0.3	0.5	0.5	1.9
Health Strategy	0.1	0.1	0.1	0.1	0.1	0.5
Compliance Management	0.1	0.1	0.1	0.1	0.1	0.5
CAM adjustment	1.5	1.5	1.5	1.5	1.5	7.7
FTE reductions	-0.2	-0.2	-0.2	-0.2	-0.2	-1.0
Other operational savings	0.0	-0.1	-0.1	-0.1	-0.1	-0.4
Total corporate services step change	**2.7**	**3.3**	**3.4**	**3.7**	**3.9**	**17.0**

<u>Salary & wages escalation</u>

For the purposes of the subsequent regulatory proposal, ActewAGL Distribution applied professional labour cost escalators in respect of the Corporate Services division and included these within the Corporate Services step change forecast. These are distinct from the utilities cost escalator applied in respect of the Electricity Networks division workforce, included within the price change component of the rate of change forecast.

ActewAGL Distribution has applied general labour cost escalators for corporate services labour. ActewAGL Distribution's proposal regarding labour cost escalation is detailed in section 3.5.3.1. General labour escalators are provided in Independent Economics' updated labour cost escalators report provided at Attachment C46. Independent Economics' updated nominal forecast escalators have been used by CEG to develop real cost escalators, which is provided at Attachment C47. The revised forecast shows a slight weakening in labour cost growth.

The updated general labour growth forecasts are provided in Table 3.18, which also shows the labour cost escalators proposed in ActewAGL Distribution's regulatory proposal for comparison.

Table 3.18 Real general labour cost escalators 2014-19

Per cent	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Regulatory proposal	0.8	1.3	1.8	1.9	1.9
Revised proposal	0.3	1.5	1.4	1.3	1.3

ActewAGL Distribution contends that labour cost escalation should be applied for corporate services as for other costs. Escalation of these labour costs does not occur with escalation of ActewAGL Distribution's other labour costs.

Software Licence escalation

ActewAGL Distribution's corporate services step change includes forecast cost escalation of seven per cent per annum for software licences from 2012/13 to 2014/15, with escalation in line with CPI for the remainder of the 2014-19 regulatory control period.

The AER draft decision did not include a step change for software licence maintenance costs relating to corporate services, on the basis that the rate of change is applied to the base year total opex.

The AER explain that if a step change is incorporated to account for higher software licence and maintenance costs a more accurate forecast for corporate services may result in isolation, but that the opex forecast as a whole will be too high.[480]

ActewAGL Distribution notes that it applies price change to opex excluding corporate services charges, therefore applying the rate of change to only Electricity Networks costs. The corporate services costs are considered as a standalone input given the shared services model and separate divisional structure to Electricity Networks. This treatment is consistent with ActewAGL Distribution's treatment of salary and wages escalation.

Therefore, ActewAGL Distribution maintains that applying real cost escalation for software licencing costs within this step change is appropriate and does not result in double counting.

Opex associated with the implementation of the core systems replacement program

ActewAGL Distribution will incur incremental opex associated with the implementation of the core system replacement program in respect of new licences and associated maintenance and support costs. This step change includes $0.5 million for these additional costs above base year levels.

As outlined in ActewAGL Distribution's regulatory proposal, the core systems replacement program was specifically undertaken to enable ActewAGL Distribution to:

- mitigate major risks throughout the business;

[480] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-157

- maintain compliance with increasing regulatory and statutory requirements;
- accurately report consumption data to retailers;
- upgrade or implement new solutions without being impeded by out-dated systems; and
- manage the stability of the ICT environment.

On this basis, ActewAGL Distribution refutes the AER's claim that implementation of the CSRP was a discretionary business decision and that ongoing costs would be offset by future efficiencies, and maintains that these costs are additional to those in the based year required to achieve the opex objectives.

The incremental ongoing operating expenditure as a result of this program is for additional licence maintenance costs from 2014/15 onwards. These costs were not included in the base year as the legacy systems were unsupported and licencing models have changed with newer software available.

Opex related to capex programs

The AER draft decision did not include a step change for the ongoing costs of software licences and maintenance as proposed by ActewAGL Distribution, as it considered these costs to be included within base opex and that IT investment should result in opex savings not opex increases.[481]

The investment profile for ICT is higher in the early years due to a range of extension projects that logically follow the major OSR and CSR programs of work completed in the 2009-2014 regulatory control period. The ICT strategy provides for ongoing investment into new foundation projects to increase ActewAGL Distribution's mobility and business information capabilities. In the outer years costs include projects to refresh ICT assets as they reach their anticipated useful life.

According to an independent benchmarking survey conducted by KPMG, ActewAGL Distribution's corporate services ICT capital expenditures have consistently performed well below the Australian utilities industry average across various key metrics. This indicates ActewAGL Distribution's relative efficiency and also a level of underinvestment in critical ICT assets compared with industry peers.

The AER's draft decision allowed for the ICT capital expenditure of $29.7m in the next regulatory control period, of which:

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[481] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-157

- $22.4m is non-recurrent capital expenditure (with $15.1m of this is primarily driven by the investment in foundational initiatives to embed new capabilities); and
- $7.3m is recurrent capital expenditure, which predominantly provides for the replacement/refresh of ICT assets as they reach their anticipated useful life.

Given the extent of non-recurrent capital expenditure, specifically being implemented to introduce new capabilities, it reasonable to expect an associated increase in the level of operational expenditure to maintain and support these new ICT assets. This opex is not included in base level of opex nor does it replace or offset opex in the base level opex.

Health strategy

ActewAGL Distribution has a dedicated Health Strategy, which is borne from the legislative requirements under the *Work Health and Safety Act 2011*, *Safety Rehabilitation Compensation Act 1988* and the *Workers Compensation Act 1951* to protect the health and safety of all employees.

The Health Strategy is aimed at providing employees with a workplace committed to improving and maintaining staff wellbeing, health and safety. It is designed to promote leadership and commitment at all levels, aligning with Environment Health, Safety and Quality's Strategy 2012-2015 of transitioning to a more proactive safety culture by the end of 2015. This strategy aligns with the People and Performance Strategy 2013- 19 in which the value of our workplace health is critical to attracting, recruiting and retaining skilled, capable staff.

Compliance management

ActewAGL Distribution's electricity network operations in the ACT are subject to a significant number of legislative and regulatory obligations. The number of obligations increased significantly during the current regulatory control period, in part due to the introduction of NECF in 2012.

With an increasing number of legislative and regulatory obligations, in 2013/14 ActewAGL Distribution upgraded its legal compliance framework and implemented a legal obligations management system (CMO).

Historically ActewAGL Distribution has relied on manual processes that are highly reliant on subject matter experts (SMEs) to ensure compliance with key regulatory obligations. The introduction of NECF in 2012 highlighted the need for a more sophisticated approach to compliance management.

The CMO system enables ActewAGL Distribution to store, update and monitor legal obligations that relate to ActewAGL Distribution's day-to-day operations. It also allows ActewAGL Distribution to identify and link an obligation to the relevant business controls that ActewAGL Distribution has in place to ensure compliance with the obligation.

Each obligation is assigned to the relevant division and the appropriate process owner within that division. CMO is updated each quarter with new and amended obligations, and then notifies process owners of changes to obligations that are assigned to them.

Implementation of the CMO database has improved end to end capability, ensuring the capture and implementation of new and amended obligations relevant to ActewAGL's operations, and monitoring of compliance against these obligations.

Opex required to efficiently manage ActewAGL Distribution's legal obligations has risen above the base year as a result of changing and increasing regulatory obligations and requirements.

Allocation of corporate services

The AER states that it has taken annual variations in the amount of corporate services to be capitalised into account in assessing the efficiency of ActewAGL's base year expenditure and it has not specifically been considered as a step change. [482]

ActewAGL Distribution has continued to include this as a step change in its revised opex forecast to ensure transparency in the allocation of opex and capex between standard control services and alternate control services under the CAM approved by the AER. Due to changes in the capex forecast, the allocation between opex and capex has changed, resulting in a minor change in this step change.

3.6.3.6 *Asset management optimisation*

As discussed in 3.7, ActewAGL Distribution's regulatory proposal for the subsequent regulatory control period applied a zero-based forecasting approach for maintenance and vegetation management expenditure, however its revised proposal is to apply a base step trend approach for all expenditure, including maintenance and vegetation management.

In adopting this approach, ActewAGL Distribution maintains that it is prudent to assess base year maintenance and vegetation management opex against its zero based forecasts to identify whether this produces annual forecasts that ensure life cycle costs are optimised and therefore reflect the efficient costs of achieving the opex objectives. Further, new ACT Government regulations require ActewAGL Distribution to operate the electricity network in a manner compliant with an asset management system, which implies zero based forecasting to minimise whole of life cycle costing. This step change is required to ensure adequate expenditure to deliver the maintenance program.

[482] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-158

In August 2013, changes were made to the *Management of Electricity Network Assets Code*, which made compliance with an asset management system standard not just best practice, but also a regulatory requirement in the ACT. Under section 5.3(3) of the updated Management of Electricity Network Assets Code, which was made under section 65 of the Utilities Act 2000, ActewAGL Distribution must have an up to date asset management system consistent with PAS 55 Asset Management and ISO 55000 Asset Management. It is understood by ActewAGL Distribution that this is not a regulatory requirement of any other DNSP.

ISO 55000 provides a suite of standards for asset management and includes ISO 55001:2014, which specifies requirements for an asset management system within the context of the organisation. This standard has an explicit focus on maintenance, renewal and enhancement activities intended to deliver sustainable outputs at the lowest whole of life cost, as opposed to prioritising work predominantly according to asset condition.

In order to comply with the changes to the *Management of Electricity Network Assets Code,* ActewAGL Distribution is working towards certification to ISO 55001:2014, which will demonstrate that the organisation is applying the principles required by the standard and this will provide the benefit of demonstrating to be operating in a 'least cost environment' consistent with its level of service obligations. Compliance with the standard implies that asset-related expenditure forecasts are set at an appropriate level to optimise life cycle costs.

It follows that in order to comply with its regulatory obligations under the Management of Electricity Network Assets Code and in turn promote efficient investment in and operation of distribution system assets over the long term, ActewAGL Distribution's maintenance and vegetation management opex forecasts must reflect the outputs of the asset management system such that life cycle cost optimisation can be achieved.

In moving to a base year approach for all opex forecasting, ActewAGL Distribution will continue to assess maintenance and vegetation management opex against zero based forecasts to identify annual forecasts that ensure life cycle costs are optimised and therefore reflect the efficient costs of achieving the opex objectives. Zero based forecasting has the benefit of providing an in-depth review of the condition and risk profile of all assets, and minimises the probability of overlooking critical tasks which may not have had adequate prior attention, particularly safety related tasks.

As a result of this assessment, ActewAGL Distribution's revised opex forecast includes a total step change of $1.1 million across the five year period to account for the annual differences in expenditure between base year opex for these categories and the zero based forecast. The annual step changes are provided in Table 3.19. This expenditure is not accounted for in ActewAGL Distribution's proposed output growth rate, which only includes a small allowance for maintenance of assets to be commissioned during the forthcoming regulatory control period and includes an implicit productivity improvement.

Table 3.19 Asset management optimisation step change costs

($m, 2013/14)	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Utilities labour	0.5	0.1	-0.1	-0.2	0.4	**0.6**
other	0.4	0.0	-0.1	-0.2	0.3	**0.5**
Total	**0.9**	**0.1**	**-0.2**	**-0.4**	**0.7**	**1.1**

3.7 Opex forecasting method

3.7.1 ActewAGL Distribution's proposal

In the subsequent regulatory proposal, ActewAGL Distribution used a combination of zero-based and base year approaches for opex forecasting, whereby a zero-based approach was used to forecast its network maintenance and vegetation management expenditure.

3.7.2 AER draft decision

The AER is not satisfied that ActewAGL Distribution's forecasting method produces an opex forecasting that reflects the opex criteria. The AER's draft decision is, therefore, to use a forecasting method that is different to ActewAGL Distribution's in determining its substitute forecast total opex. Specifically, the AER used an approach consistent with its Expenditure Forecast Assessment Guideline, whereby it forms a view on an efficient base opex that reflects the opex criteria, then applies a forecast rate of change incorporating changes in input prices, output and productivity, and accounts for 'step changes' for expenditure not captured in the base or rate of change. That is, whereas ActewAGL Distribution used a combination of zero-based and base year methods, the AER's forecasting method is to use a base year method uniformly for all opex categories with the exception only of debt raising costs.[483]

In making this decision, the AER expressed the view that using category specific forecasting methods, such as ActewAGL Distribution's zero-based method, for some opex categories may produce better forecasts of expenditure for those categories but this may not produce a better forecast of total opex. This is because the use of hybrid forecasting methods can produce biased opex forecasts, which is inconsistent with the opex criteria. Specifically, the AER reasoned that, if a category specific forecasting method is used to forecast opex categories with low base year

[483] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-159.

expenditure and/or with a greater rate of change than total opex, forecast opex will systematically exceed the efficient level of opex.[484]

For this reason, the AER concludes:[485]

[W]e have not used category specific forecasting methods to separately forecast any of ActewAGL's opex categories in our substitute total opex forecast. We formed our substitute forecast total opex using our guideline forecasting approach with all opex categories included in base opex.

3.7.3 ActewAGL Distribution's response and revised proposal

While ActewAGL Distribution is content to accept the AER's forecasting method for the reasons discussed below, it observes that the AER's draft decision on the opex forecasting method further evidences that the AER has misconstrued the task with which it is charged by the Rules as being to determine upon its own opex forecast with little regard to ActewAGL Distribution's own forecast, rather than, at least in the first instance, to assess ActewAGL's Distribution's forecast.

ActewAGL Distribution does not agree with the AER that, if category specific forecasts are used for categories where base year opex is low and/or for which the rate of change is greater than that for total opex, the total opex forecast will systematically exceed the efficient level of opex.[486] Rather, ActewAGL Distribution is of the view that the assessment of whether the forecast reasonably reflects the efficient level should be based on the costs required to achieve the opex objectives, which may or may not exceed the trended base opex forecast.

While the AER's stated 'position' (in Section D.1 of Appendix D) is that it is not satisfied that ActewAGL Distribution's forecasting method produces an opex forecast that reasonably reflects the opex criteria, the AER's 'reasons for position' (in Section D.4) do not provide any basis for rejecting ActewAGL Distribution's forecasting method. Those reasons suffice only to support the selection of the AER's own preferred forecasting method. Indeed, the entire focus of the discussion in Appendix D is on the forecasting method to be used by the AER in determining its own substitute total opex forecast. The AER's final, concluding paragraph, in particular, is expressed solely by reference to the forecasting method for use in deriving the AER's own

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[484] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-160.

[485] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-161.

[486] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, pages 7-160 and 7-161

substitute total opex forecast.[487] ActewAGL Distribution considers the AER has misdirected itself, and committed reviewable error, insofar as it puts aside ActewAGL Distribution's opex forecast and derives its own substitute opex forecast with little regard to the former.

Putting this matter to one side, ActewAGL Distribution is content to accept the AER's preferred forecasting method notwithstanding that the AER did not advance any logical basis for its conclusion that ActewAGL Distribution's forecasting method does not produce an opex forecast that reasonably reflects the opex criteria. Accordingly, ActewAGL Distribution's revised proposal is to adopt a base year (base-step-trend) approach for the forecasting of opex for all opex categories. The reason for this is twofold.

First, as detailed in Sections 3.4.4 and 3.4.5, ActewAGL Distribution maintains that a revealed cost approach is preferable and consistent with the incentive based regulatory framework, and notes that the use of revealed base year expenditure is integral to the function of the EBSS. ActewAGL Distribution maintains its position that the EBSS should continue to apply during the 2014-19 regulatory control period. If the EBSS is to be maintained, the use of a hybrid forecasting approach may result in category specific forecasts being excluded for the purposes of the EBSS, which would result in reduced incentives for service providers to pursue efficiency improvements and penalties for efficiency losses.

Secondly, ActewAGL Distribution contends that use of a base step trend approach for all opex forecasting provides for a more transparent forecast proposal and review process, whereby any variations from the base year that are not captured in the rate of change are addressed through step changes. ActewAGL Distribution expects that this approach should contribute to greater consistency in regulatory decision making in future regulatory control periods.

In proposing to move to a base year approach for all opex, ActewAGL Distribution notes that as a prudent operator, it will continue to assess base year maintenance and vegetation management opex against its zero based forecasts to ensure that forecasts enable optimisation of life cycle costs and therefore reflect the efficient costs of achieving the opex objectives. Annual variances between the base opex forecasts and zero based forecasts are driven by movements in the maintenance schedule which is determined by asset specific maintenance plans developed to optimise life cycle costs. This may result in positive or negative step changes within a regulatory control period, but this is intended to achieve lowest whole of life cycle costs. Similarly, this may

[487] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, pages 7-160 and 7-161. The final, conclusionary paragraph reads: *'For the above reasons we have not used category specific forecasting methods to separately forecast any of ActewAGL's opex categories in our substitute total opex forecast. We formed our substitute forecast total opex using our guideline forecasting approach with all opex categories included in base opex.'*

result offsetting capex savings. ActewAGL Distribution maintains that this is a prudent, efficient and realistic approach to maintenance and vegetation management opex forecasting and enables compliance with its regulatory obligation to have an up to date asset management system consistent with PAS 55 Asset Management and now ISO 55000 Asset Management, as detailed in Section 3.6.3.6 As a result, ActewAGL Distribution's revised opex forecast includes a total step change of $1.5 million across the five year period to account for the annual differences in expenditure between base year opex for these categories and the zero based forecast. This is detailed in Section 3.7.

3.8 Transition to more efficient costs

3.8.1 Overview

ActewAGL Distribution contends that the AER has a discretion under the Rules to establish a glide path to allow an achievable transition to the AER determined level of opex and, further, that, in the event that the AER makes a final decision on opex that is substantially similar to that proposed in the draft decision, the only correct and reasonable decision is to exercise that discretion to establish such a glide path.

In the draft decision the AER raises the possibility of transition to the level of opex that it has determined to be efficient. The AER states in the Overview to its draft decision:[488]

It is not clear from the information before us that transitioning to an efficient level of opex is consistent with the incentive framework provided by the NEL and the NER. We will, however, consider the issue further in view of any submissions received on this matter in response to our draft decision.

The AER further comments in Attachment 7:[489]

As outlined in our Guideline, if the prudent and efficient opex allowance to achieve the opex objectives is lower than a service provider's current opex, we would expect a prudent operator would take the necessary action to improve its efficiency. We would expect a service provider (including its shareholders) to wear the cost of any inefficiency. To do otherwise, [sic] would mean electricity network consumers would fund some costs of a service provider's inefficiency. Accordingly, if our opex forecast is lower than a service provider's current opex we would generally not consider it appropriate to provide a transition path to the efficient allowance. This approach appears to be reflected in the NER, which provides that we must be satisfied that the opex forecast reasonably reflects the efficient

[488] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Overview*, November, page 11

[489] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-16

costs of a prudent operator given reasonable expectations of demand and cost inputs to achieve the expenditure objectives.

3.8.2 ActewAGL Distribution's response

As explained in this Chapter 3 of the revised regulatory proposal, ActewAGL Distribution does not accept the AER's draft decision on opex. It considers that the AER has failed to discharge its procedural obligations under the Rules and common law in developing and applying its benchmarking analysis relied on in making that decision, that its decision is otherwise not in accordance with law, involves a material error, or material errors, of fact and/or an incorrect exercise of discretion, and/or is unreasonable, and that its decision does not contribute to the achievement of the NEO and, thus, does not result in a draft decision on opex or an overall draft decision that contributes to the achievement of the NEO to the greatest degree as required by Section 16(2)(d) of the NEL.

However, in the event that the AER makes a final decision on opex that is substantially similar to that proposed in the draft decision, ActewAGL Distribution considers that the AER has a discretion under the Rules to establish a glide path to allow an **achievable** transition to the AER determined level of opex and, further, that the only correct and reasonable decision is to exercise that discretion to establish such a glide path.

3.8.2.1 *The discretion to establish a glide path*

While Clauses 6.5.6(c) and (d) and 6.12.1(4) of the Rules require the AER to be satisfied that the opex forecast reasonably reflects the efficient costs of a prudent operator given reasonable expectations of demand and cost inputs to achieve the expenditure objectives, ActewAGL Distribution considers that there is sufficient discretion and judgment inherent in the task with which the AER is charged by those provisions to enable it to establish a glide path.

As discussed in Section 3.2.4 above, the AER is required to exercise discretion and judgment in deciding the forecast opex that it is satisfied reasonably reflects the opex criteria. The formulation of the statutory test for that decision (in Clauses 6.5.6(c) and 6.12.1(4)(ii) of the Rules) by reference to whether the forecast 'reasonably reflects' the opex criteria introduces a significant leeway of choice for the AER, while the requirement that the AER be 'satisfied' also affords it some leeway in deciding whether a forecast is reasonable. Further, as the opex criteria by reference to which those criteria are specified are evaluative and subjective in nature, the AER is required to exercise judgment in deciding whether the criteria are satisfied.

The AER must exercise the discretion and judgment inherent in deciding forecast opex in a manner that will contribute to the achievement of the NEO and having regard to the RPPs.

In the alternative, ActewAGL Distribution considers that the AER's discretion with respect to the control mechanism would extend to establishing a glide path.

Clause 6.12.1(11) of the Rules requires the AER to include in ActewAGL's distribution determination for the subsequent regulatory control period a decision on the form of the control mechanism (including the X factor) for standard control services and on the formulae that give effect to that control mechanism. Clause 6.12.3(c1) of the Rules, in turn, provides that the formulae that give effect to the control mechanisms must be as set out in the relevant framework and approach paper unless the AER considers that unforeseen circumstances justify departing from the formulae as set out in the paper.

However, in its *Stage 1 Framework and approach paper ActewAGL* for the transitional and subsequent regulatory control periods published in March 2013 (Stage 1 F&A Paper), the AER proposes to apply the following formulae to standard control services which formulae provide for the inclusion of terms to establish transitional arrangements of the kind presently in issue:[490]

(1) $$MAAR_t \geq \frac{(\sum_{i=1}^{n} \sum_{j=1}^{m} p_{ij}^{t} q_{ij}^{t-2})}{kWhtransported_{t-2}}$$ i=1,...,n and j=1,...,m and t=1,...,5

(2) $$MAAR_t = AAR_t + \frac{(I_t + T_t + B_t)}{kWhtransported_{t*}}$$

(3) $$AAR_t = AAR_{t-1}(1 + CPI_t)(1 - X_t)$$

The B_t term is defined in the Stage 1 F&A Paper, for the purposes of the above formulae, as "the sum of annual adjustments in year t. To be decided in the final decision". The T_t term is defined as "the sum of transitional adjustments in year t. To be decided in the final decision".[491]

There is little discussion or explanation of the AER's specification of the proposed formulae for standard control services in the Stage 1 F&A Paper. In its *Discussion paper Formulae for control mechanisms - Revised: Matters relevant to the framework and approach for NSW and ACT DNSPs 2014-19* of February 2013 published for the purpose of consulting on the proposed formulae, however, the AER observed that:[492]

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[490] See Attachment C58, AER, 2013, *Stage 1 Framework and approach paper ActewAGL*, March, pages 57 and 58

[491] See Attachment C59, AER, 2013, *Discussion Paper, Formulae for control mechanisms – Revised, Matters relevant to the framework and approach for NSW and ACT DNSPs 2014-19*, February, page 10

[492] See Attachment C59, AER, 2013, *Discussion Paper, Formulae for control mechanisms – Revised, Matters relevant to the framework and approach for NSW and ACT DNSPs 2014-19*, February, page 10

Adjustments made for incentive schemes and annual/transitional adjustments are set out in generic form to allow for future specification.

Having regard to their broad definitions in the Stage 1 F&A Paper, the B_t term and the T_t term encompass transitional adjustments to enable a "glide path".

The AER recognises, in the establishment of the B_t and T_t terms in the formulae for standard control services in the Stage 1 F&A Paper that Clause 6.5.9(3) of the Rules does not preclude the AER from allowing adjustments to a DNSP's control mechanism which diverge from the DNSP's total revenue requirement and would extend to allowing an adjustment to establish a glide path. The exercise by the AER of its discretion with regard to the control mechanism in a distribution determination is, however, governed by the NEO and the RPPs.

It follows that, where the establishment of a glide path contributes to the achievement of the NEO and is consistent with the RPPs, the only correct and reasonable course open to the AER is to establish such a glide path.

3.8.2.2 *Establishment of glide path correct and reasonable where AER's opex draft decision becomes final*

As discussed in Section 3.1 above, the AER's draft decision on opex reduces ActewAGL Distribution's proposed total opex for the 2014-19 period by $157 million ($2013/14) or approximately 42 per cent. In deriving its own forecast opex, the AER departs significantly from its own and its predecessor's previous regulatory approach to estimating base opex, resulting in a proposed AER opex allowance that represents a marked reduction to the opex allowances for the 2004 - 09 and the 2009 - 14 regulatory control periods, as well as being materially lower than ActewAGL Distribution's historical opex in those periods.

The financial impact of this reduction was provided in Chapter 2.

Furthermore, ActewAGL Distribution has submitted in Chapter 2 that to transform its business model and operations to meet the harsh expenditure cuts proposed by the AER requires significant restructuring costs to be incurred, and there is no allowance for such costs in the regulatory reset process.

In addition, ActewAGL Distribution must ensure that organisational change is managed over a sufficient time period such that the intended benefits of the change, such as expected cost reductions, are sustainable in the long-term and do not put at risk the security of supply, reliability, quality and safety.

These risk and potential consequences on service reliability and safety were also explained in Chapter 2.

Rationale for the establishment of a glide path

The magnitude of expenditure cuts proposed by the AER are unrealistic and likely to be detrimental to the long interests of consumers, and lead to a higher risk of reduced security of supply, increased risk of safety standards and increased risk of lower reliability. Professor Newbery notes that:

*In most regulated industries, glide-paths have generally been employed by regulators rather than full P0 adjustments when the scale of the inefficiency adjustment has meant that it was not **feasible** (i.e., reducing staff numbers, adopting new business practices, impact on financeability) for the inefficient company(ies) to close the entire gap to the frontier in a single year. Glide-paths are therefore designed to reflect:*

- *the degree of catch-up considered to be required to achieve an efficient operating cost base;*
- *the time period for which this is could be achieved; and*
- *how the 'efficient frontier' was calculated* [493]

…

The information [….] indicates that more often than not regulators apply a glide-path. The evidence from the UK suggests that only when regulators have collected data on a transparent and consistent basis over a long period, and have tried and tested models, are they confident enough to not make a further discretionary adjustment to the frontier, and that the frontier is then based on the upper quartile. Even then it is worth noting that regulators tend to make adjustments, including mitigating factors, for one-off expenditure, menu regulation, and/or company specific-factors which all impact on companies' regulated allowances. In addition, with a few exceptions, regardless of technique or choice of benchmark regulators have tended to 'offset' the catch-up to the frontier required by the companies. [494]

The AER's own technical advisors, from within the ACCC, and other regulators have recognised the need to allow a 'glide path' to the efficient level of opex, particularly in circumstances where a large opex cut is required by the regulator. Imposing a substantial reduction in opex without a glide path results in what is likely to be an unachievable cost target which, in turn, places service quality and the long term interests of consumers at risk. The 42 per cent reduction in ActewAGL

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[493] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 39

[494] See Attachment C3, CEPA, 2015*, Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, page 44

Distribution's opex allowance imposed by the AER in its draft decision is clearly substantial, and cannot realistically be achieved in the first year of the regulatory control period.

For example, the ACCC Regulatory Development Branch, in the context of a technical report on the use of economic benchmarking by the AER, has noted:[495]

... the ability of an NSP to achieve cost savings by removing inefficiency in opex quickly may be limited by a number of factors. These factors include the scope of the cost inefficiency, business practices and the challenges of renegotiating workplace arrangements. It may be the case that efficient opex could only be achieved by the end of a five-year regulatory period (i.e., catching up with its peers). That is, it may take the full five-year regulatory period before the relatively inefficient NSP can 'catch up' with its peers.

As noted above, the 'scope of the cost inefficiency' claimed by the AER is substantial. In addition, the AER views a source of that inefficiency as relating to ActewAGL Distribution's current business practices and workplace agreements. On this basis, it appears that the AER's own advisors would consider the application of a glide path appropriate in the case of ActewAGL Distribution.

The ACCC has also recognised the potential role for a glide path in situations where major changes are proposed, to protect the legitimate business interests of businesses and to avoid regulatory shock. In a telecommunications industry discussion paper on pricing of mobile termination access services (MTAS) the ACCC said:[496]

the ACCC is cognisant that all of the above options will likely produce a new MTAS rate that departs significantly from the current rate. Taking into account the legitimate business interests of the MNOs (mobile network operators), it may be appropriate to consider transitional prices in implementing the new regime so as to minimise regulatory shock.

Other regulators have emphasised the need to set achievable targets, which deliver savings to customers while recognising the importance of ensuring service quality, financial viability and a stable platform for future investment over the longer term. Relevantly, in all of the cases discussed below, the size of the proposed reduction in opex which these regulators considered would be unrealistic to impose without a glide path is *materially below* that which has been determined by the AER in the draft decision.

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[495] See Attachment C18, ACCC/AER Regulatory Development Branch, 2013, *Economic Benchmarking Model: Technical Report,* page 19

[496] See Attachment C60, ACCC, 2011, *Domestic Mobile Terminating Access Service (MTAS), Public inquiry to make an Access Determination, Discussion paper*, June, page 20

In the United Kingdom, OFWAT decided to use a three-year glide path for companies with actual existing costs above the average cost to serve (ACTS), arguing that this approach represented an appropriate balance between delivering savings for customers while not setting unachievable cost reduction targets for high-cost companies. In particular, OFWAT noted:[497]

In taking a decision on whether to use a glide path, we need to consider the overall scale of the efficiency challenge we apply in the round. We want to deliver savings for customers by reducing inefficient behaviour but without setting unachievable cost reduction targets for high-cost companies. In our view, a five-year glide path does not result in sufficiently stretching cost reduction targets for high cost companies. At the same time, not using a glide path would result in some companies being set unachievable targets for 2015-16 given the spread of efficiency in delivering these services at the moment. We have therefore decided that the best approach is to use a three-year glide path, with companies delivering the full (average costs) efficiency challenge by 2018-19. The move to ACTS has been well trailed and effective companies will already be able to start taking action to reduce costs now in order to achieve ACTS by 2018-19.

The Utilities Commission in the Northern Territory, in the context of its decision regarding the maximum allowed revenue for PWC Networks, approved a glide-path for allowed opex with the purpose of transitioning PWC Networks to a lower cost path to account for a 27 per cent cost difference between PWC Networks and the average of its peers. In approving this glide path, the Commission noted:[498]

A key question for the Commission was the timeframe required for such a performance gap to be removed. The Commission's view in the Draft Determination was that the answer would depend on several factors, including the size of the efficiency gap, its possible causes and the degree of cost flexibility that PWC Networks could reasonably be expected to achieve.

If the timeframe was set for a period which was too short, there would be scope for PWC Networks to be placed under excessive financial stress and for service quality to drop substantially as maintenance programs could be terminated to meet overly onerous annual cost reduction targets. This could impact on the significant improvement program currently underway and run the risk of retail customers seeing short term price reductions at the expense of receiving lower quality services in the future.

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[497] See Attachment C61, OFWAT,2013, *Setting price controls for 2015-20 – final methodology and expectations for companies' business plans*, July, page 101

[498] See Attachment C62, Utilities Commission, 2014, *2014 Network Price Determination – Final Determination – Part A: Statement of Reasons*, April, page 104

In Ireland the Commission for Energy Regulation, in the context of its decision on the maximum allowed revenue for Bord Gais Networks, approved a glide path for allowed opex to account for a 15 per cent efficiency gap. In approving this glide path the Commission noted:[499]

This final decision paper would have set a total distribution Opex of €392m for the five year period covered by PC3, which represented a significant reduction of €71m (15%) below the €463m originally requested by the distribution business. The CER believes that while BGN should only be allowed a level of Opex that covers efficient costs, it is also recognised that BGN will be challenged to immediately reduce their Opex to the levels proposed in the consultation document. It is also of the utmost importance that BGN continue to maintain the highest of safety standards in their operation of the gas distribution network.

While the CER expects that BGN will be able to introduce measures to reduce costs and improve efficiency, this may take some time. Therefore the CER has allowed an additional €5m in year 1 and €3m in year 2 of the price control in order to provide BGN with a glide path to efficiency. These additional revenues will ensure that BGN continue to maintain and operate the network to the highest safety standards while allowing them time to make the necessary adjustments to improve efficiency.

In relation to the Irish water industry the Commission for Economic Regulation has noted:[500]

Essentially the utility must provide more for less – it must constantly look to provide greater service and quality to its customers at a lower cost. However, the necessity for cost efficiencies must be balanced with the other principles outlined above – stability, predictability and sustainability. For example, it would not make sense for the regulator to determine that an overly ambitious level of operational efficiency is imposed on the utility in its first year of regulation, which in essence is unachievable for the utility. Such a decision would not provide a stable platform for the utility to invest capital in the short to medium term because of the heavy focus on its operational costs. It would be far more appropriate to put the utility on an efficiency glidepath, which gives the utility time to reduce its operational costs and improve its operational efficiencies over a consecutive numbers of years.

Risk of unachievable opex adjustments without a glide path

Professor Newbery has supported his opinion on the desirability of a glide path by referring to Meyrick (2003):[501]

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[499] See Attachment C63, Commission for Energy Regulation, 2012, *Decision on October 2012 to September 2017 Distribution Revenue for Bord Gais Networks, Decision Paper,* November, page 52

[500] See Attachment C64, Commission for Energy Regulation, 2013, *Economic regulatory framework for the public Irish water services sector, Consultation paper,* October, pages 13 to 14

Given the capital intensive nature of electricity lines businesses and the long lived nature of the assets involved, it is unrealistic to expect lines businesses to be able to remove large productivity gaps in a short space of time. Rather, a timeframe of a decade, or two five–year regulatory periods, is likely to be necessary for businesses performing near the bottom of the range to lift themselves into the middle of the pack. This timeframe would allow sufficient time for asset bases to be adjusted significantly, new work practices to be adopted and bedded down and for amalgamations and rationalisations to be implemented and consolidated. It is, however, reasonable to expect profitability levels to be adjusted over a shorter period, say one regulatory period of five years. This should allow sufficient time for adjustment in a sustainable fashion without incurring the risk of financial stress or failure resulting from large P0 adjustments.[502]

In almost all cases regulators have taken a more cautious approach than using a simple frontier in order to recognise the limitations of the modelling and the economic costs and risks placed on the companies. This is not dissimilar to the revenue and pricing principles that the AER must take into account as set out in Section 7A of the National Electricity Law (NEL).

Conclusions

ActewAGL Distribution contends that, if the AER makes a final decision on opex that is substantially similar to that proposed in the draft decision, the only correct and reasonable decision is for the AER to establish a glide path. In these circumstances, a decision to establish a glide path would contribute to the achievement of the NEO and be consistent with the RPPs, and would be materially preferable to a decision not to establish a glide path.

In exercising its discretion whether to establish a glide path, the NEO and the opex factors require the AER to consider the impacts of its opex decision in the absence of such a glide path on quality, safety, reliability and security, against the background of ActewAGL Distribution's present circumstances. This could be expected to include having regard to:

- the speed with which it is realistic to expect ActewAGL Distribution to be able to achieve the opex allowance, and the impact on its financial viability and therefore its ability to continue to maintain the quality and reliability of the network; and

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[501] See Attachment C3, CEPA, 2015, *Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January, pages 40-41. Professor Newbery notes that the Meyrick report was led by Dr. Denis Lawrence who is now Director of Economic Insights and who led the benchmarking work for the AER.

[502] See Attachment C35, Meyrick and Associates, 2003, *Regulation of Electricity Lines Businesses Resetting the Price Path Threshold – Comparative Option*, September, page 63

- whether its opex allowance is achievable in practice, and the costs associated with any restructuring necessary for the business to be able to move to the efficiency frontier.

ActewAGL Distribution maintains that reducing its opex allowance immediately by over 40 per cent, particularly in circumstances where the 2014-19 period to which that allowance relates has commenced, is not a decision that, in the absence of a glide path, is likely to contribute to the achievement of the NEO. Given ActewAGL Distribution's current operational structure and the time involved in effecting cost rationalisation of the extent required to operate within the proposed opex allowance, consumers' long term interests in quality, safety, reliability and security of supply would be significantly deleteriously affected by the AER's decision.

Therefore, a glide path represents a balanced way to provide strong incentives for ActewAGL Distribution to deliver its services in the most efficient way, while also protecting the long term viability of the business and the interests of consumers.

ActewAGL Distribution would continue to be subject to incentives to reduce costs. The glide path would be compatible with the incentive framework created by the Rules.

In summary, the need for a balanced and reasonable approach to transitioning to a significantly lower opex allowance has been recognised in a wide range of regulatory contexts and is consistent with the requirements of the Rules and the law. A glide path should be adopted by the AER, if it continues to reject ActewAGL Distribution's opex proposal.

3.8.3 Options for implementing a glide path

ActewAGL Distribution considers that the AER should use its discretion to implement a glide path via an annual transitional adjustment in the control mechanism for standard control services.

For the 2014-19 period, the AER has decided to apply an average revenue cap to ActewAGL Distribution's standard control services. Under this mechanism, the AER sets a maximum average revenue allowance (MAAR) for each year. In the annual network pricing approval process ActewAGL Distribution must demonstrate compliance with the average revenue cap by showing that the average revenue expected from its proposed tariffs in year t is less than or equal to the MAAR for year t. The AER has included in the formulae for calculating $MAAR_t$ terms to allow for transitional and annual adjustments (T_t and B_t).

The transitional adjustment term (T_t) could be defined as an opex efficiency transitional adjustment. To give effect to a glide path, the adjustment would be a positive dollar amount. The adjustment could be calculated as a percentage of the difference between ActewAGL Distribution's opex forecast (as proposed in the subsequent regulatory proposal) and the opex on the efficient frontier (as determined by the AER in the final determination). The glide path could be implemented by reducing the percentage, and the efficiency adjustment, each year. For example, at the start of the 2014-19 period, the opex adjustment could be set at 50 percent of the difference between ActewAGL Distribution's opex forecast and the AER determined opex. The adjustment could be reduced each year, to zero by the final year of the period.

In the hypothetical example shown below, the difference between the ActewAGL Distribution's proposed opex and the AER's allowance over the period is $150 million.[503] Under the hypothetical glide path, $30 million of this difference is added back to the revenue allowance over the period, via the annual transitional adjustment.

Table 3.20 Hypothetical T factor adjustment

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
ActewAGL Distribution opex proposal ($m)	75	75	75	75	75	**375**
AER opex allowance ($m)	45	45	45	45	45	**225**
Difference ($m)	30	30	30	30	30	**150**
Glide path	na*	50%	30%	20%	0%	
T factor adjustment ($m)	na	15	9	6	0	**30**

* Not applicable because the T factor adjustment would apply via the annual network pricing proposal, and the 2014/15 transitional year proposal has already been approved.

The adjustment via the control mechanism would not involve a change to the basis of the control mechanism. The proposed glide path would simply require one of the terms in the AER's formula to be defined in a certain way – that is, as a transitional efficiency adjustment.

3.9 *ActewAGL Distribution's revised regulatory proposal for opex*

3.9.1 ActewAGL Distribution's proposal

ActewAGL Distribution's regulatory proposal included forecast opex for standard control services of $377.3 million ($2013/14), or an average of $75.5 million per year for the 2014–19 regulatory

503 In this hypothetical example, a four year glide path is assumed. However, as ActewAGL Distribution has submitted in Chapter 2, and supported by Professor Newberry, international best practice, management consulting firms and academic, including the lead advisor to the AER, Dennis Lawrence (whilst with Meryck) that multiple regulatory control periods are likely to be required to achieve the expenditure cuts proposed by the AER.

control period, excluding debt raising costs and EBSS carry-over amounts. This total opex forecast was comprised of:

- Base opex for the 2014 - 19 period of $224.7 million based on adjusted actual opex incurred in the 2012/13 revealed cost base year, excluding maintenance and vegetation management;
- Zero-based category specific forecasts for network maintenance and vegetation management expenditure of $110.7 million, including $3.1 million for real price growth and $0.4 million for output growth;
- Step changes, which resulted in an increase to base opex for the 2014 – 19 regulatory control period of $35.3 million; and
- Forecast changes in input prices, which resulted in an increase to base opex for the 2014-19 regulatory control period of $6.7 million (not including maintenance and vegetation management, for which real price growth was incorporated into the zero-based forecast).

3.9.2 AER draft decision

In its draft decision, the AER states that it is not satisfied that ActewAGL Distribution's forecast opex reasonably reflects the opex criteria and has therefore developed an alternative estimate of $220.3 million.[504] This represents a 42 per cent reduction on ActewAGL Distribution's forecast. For the reasons set out in this chapter 3, ActewAGL Distribution contends that this is inconsistent with the NEO and the long term interests of consumers, and if implemented will adversely impact the ability of ActewAGL Distribution to provide safe, reliable and secure supply at an efficient price.

3.9.3 ActewAGL Distribution's revised regulatory proposal

ActewAGL Distribution maintains that the use of a revealed cost approach, in conjunction with its proposed rate of change and step changes, results in an opex allowance that is consistent with the requirements of the Rules and the law and is materially preferable to the AER's draft decision.

ActewAGL Distribution's revised opex forecast for standard control services is $371.2 million, or an average of $74.2 million per year for the 2014–19 regulatory control period, excluding debt raising costs and EBSS carry-over amounts. ActewAGL Distribution's revised opex forecast is shown in

Table **3.21**.

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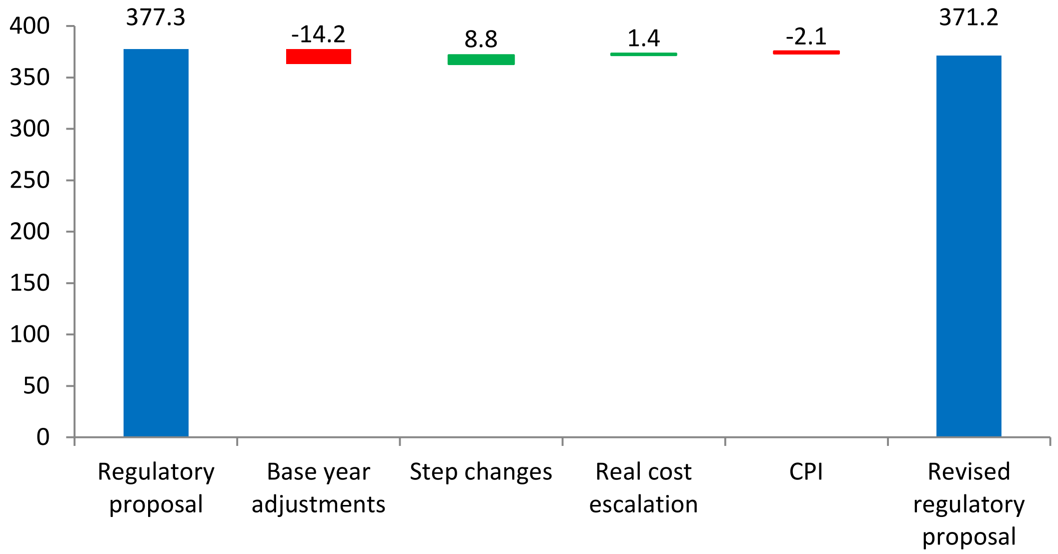
[504] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Attachment 7: Operating expenditure*, November, page 7-7

Table 3.21 Revised standard control opex base step trend forecast 2014-19

($million, 2013/14)	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Regulatory 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***
Revised proposal						
Efficient base year (2012/13) opex	63.1	63.1	63.1	63.1	63.1	**315.5**
Step changes	10.4	9.3	6.9	8.3	9.1	**44.1**
Real cost escalation	1.3	1.7	2.2	2.7	3.3	**11.2**
Output growth	0.0	0.1	0.1	0.1	0.1	**0.4**
productivity growth	0.0	0.0	0.0	0.0	0.0	**0.0**
Forecast controllable opex	**74.8**	**74.2**	**72.3**	**74.3**	**75.6**	**371.2**
Debt raising costs	1.0	1.0	1.0	1.0	1.1	5.1
DMIS	0.1	0.1	0.1	0.1	0.1	0.6
Total forecast opex	**75.9**	**75.3**	**73.5**	**75.4**	**76.7**	**376.9**
Distribution	*61.6*	*61.1*	*59.6*	*61.2*	*62.2*	*305.7*
Transmission	*14.3*	*14.2*	*13.9*	*14.2*	*14.5*	*71.2*

ActewAGL Distribution's revised opex forecast is $6.1 million, or 1.6 per cent lower than the forecast in the regulatory proposal. Drivers of this change are shown in Figure 3.11 below.

Figure 3.11 Proposed opex forecast bridge ($ million 2013/14)



4 Capital expenditure

4.1 Introduction

ActewAGL Distribution proposed a capital expenditure (capex) program of $372.2 million ($2013/14) for the 2014-19 period to continue key capex reform programs initiated in the previous period aimed at ensuring the ongoing reliability of the network, and alignment with the ACT Electricity Distribution Supply Standards Code (2013).

This forecast expenditure is largely driven by the continuation of zone substation augmentation to meet demand for electricity in new urban areas and meet reliability standards, as well as an increased focus on asset renewal and replacement to address an increase in reactive maintenance in the 2009-14 period.

The AER did not accept ActewAGL Distribution's proposed total forecast capex of $372.2 million ($2013/14) in its draft decision, concluding that it was not satisfied that this proposed forecast capex reasonably reflects the capex criteria. The AER concluded that it was satisfied that its own alternative estimate of ActewAGL Distribution's total forecast capex for 2014-19 of $244.2 million ($2013/14) reasonably reflects the capex criteria. This represents a 34.4 per cent reduction from ActewAGL Distribution's proposed capex program.[505] Table 4.1 below summarises the AER's draft decision on capex.[506] Unless otherwise specified, all financial information in this chapter is stated in real 2013/14 dollar terms.

Table 4.1 AER draft decision on ActewAGL Distribution's total forecast capex

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
ActewAGL Distribution proposal	75.3	70.3	85.8	74.5	66.3	372.2
AER draft decision	59.2	47.8	51.8	44.8	40.6	244.2
Difference	**-16.1**	**-22.5**	**-34**	**-27.7**	**-25.7**	**-128**

[505] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-9

[506] This Table is substantively similar to the AER's Table 6-1 appearing on p. 6-9 of AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*

The AER's draft decision on capex is largely driven by reductions to ActewAGL Distribution's proposed forecast augmentation and replacement capex for the 2014-19 period, from $99.5 million to $61.7 million for augmentation capex and from $132.3 million to $98.6 million for replacement capex.

Specifically, the AER was not satisfied that ActewAGL Distribution’s proposed capex program reasonably reflects the capex criteria because:[507]

- ActewAGL Distribution’s forecasting methodology does not include a top-down assessment, is overly conservative and doesn’t adequately justify the timing and priority of its capex program;
- ActewAGL Distribution's augmentation capex forecasts are overstated and exceed the amount required to achieve the capex objectives, as ActewAGL Distribution did not advance sufficient evidence in respect of five augmentation projects in its augmentation capex program that those projects were the efficient solutions to the relevant network constraints;
- ActewAGL Distribution's replacement capex forecasts are overstated and exceed the amount required to achieve the capex objectives because these amounts are around 26 per cent higher than ActewAGL Distribution’s historical trend, and compare unfavourably with other electricity distribution businesses on AER’s replacement capex benchmarking;
- ActewAGL Distribution's capitalised overhead forecasts are not consistent with the 3 per cent average proportion of ActewAGL capitalised overheads to total capex in the 2009/10-2013/14 regulatory control period, or the reduced amounts of capex included in the AER’s alternative estimate; and
- It did not accept ActewAGL Distribution’ proposed commodity and labour escalators.

[507] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, pp. 6-10 to 6-12

The AER accepted ActewAGL Distribution's proposed forecast of customer connections capex for the 2014-19 period (of $91.4 million), capital contributions (of $41.16 million) and non-network capex (of $37.9 million, excluding capitalised overheads).[508]

The AER did, however raise concerns regarding discrepancies between the figures for ActewAGL Distribution's proposed forecast capital contributions and non-network capex appearing in each of the completed RIN templates and the populated PTRM accompanying ActewAGL Distribution's regulatory proposal for the subsequent regulatory period.[509]

ActewAGL Distribution rejects the AER's alternative estimate for capex over that period because it is substantially lower than that required for ActewAGL Distribution to achieve the capex objectives. A summary of ActewAGL Distribution's response to the key elements of the AER's draft decision is provided in Table 4.2 below.

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[508] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, pp. 6-10 to 6-11, 6-41 to 6-44 and 6-68 to 6-72. While the AER accepted ActewAGL Distribution's forecast of total non-network capex as a reasonable estimate of the efficient costs required for this capex category, it refers on two occasions on pages 6-69 to further review being warranted to confirm the need and timing of the proposed expenditure, on the first occasion in respect of the forecast non-network capex program generally and on the second occasion in respect of the forecast motor vehicles and ICT capex programs. ActewAGL Distribution understands the AER to be referring to the further reviews conducted by the AER in making its Draft Decision that is the subject of the discussion proceeding each of these references. Lest ActewAGL Distribution have misunderstood the AER, however, it observes that, if the AER were to undertake material additional analysis not reflected in the Draft Decision, as a consequence of which it were minded to disallow any part of ActewAGL Distribution's forecast of total non-network capex, the AER would have an obligation at law to consult on that analysis and provide ActewAGL Distribution with an opportunity to make submissions on it prior to making its final determination. This obligation arises as a consequence of the AER's obligation under section 16(1)(b) of the NEL (in respect of which the AEMC relevantly observed in its 2012 Rule Determination (a p. 111) that '[i]t is noted that clause 16(1)(b) of the NEL protects a NSP from any material change in the AER's analysis without notification') and its common law obligation to accord procedural fairness.

The AER refers to a non-network capex allowance of $37.9 m ($2013/14) on page 6-11 of its Draft Decision and $50.7 million ($2013/14), including Network ICT on page 6-68. Both figures are exclusive of capitalised overheads. ActewAGL Distribution rejects the AER's alternative estimate for capitalised overheads. This is discussed in section 4.6 of this revised proposal.

[509] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, pp. 6-11 to 6-12

Table 4.2 Summary of ActewAGL Distribution's response to key elements of the AER's draft decision

Component	AER*	Does ActewAGL Distribution adopt the approach in the draft decision?
Augmentation capex	$61.7m	No
Replacement capex	$98.6m	No
Capitalised overheads	$ 7.6m	No
Real material cost escalation	0%	No

* ($2013/14) exclusive of capitalised overheads

This Chapter 4 responds to each of the AER's key concerns with ActewAGL Distribution's proposed capex program. In summary, ActewAGL Distribution demonstrates that:

- ActewAGL Distribution undertook a top-down, holistic assessment, including trend analysis and an assessment of capex/opex trade-offs, of its capex forecasts proposed in its regulatory proposal for the subsequent regulatory period on the basis of bottom up build, and its network planning criteria are appropriate and deliver comparable results with those of other DNSPs operating in the NEM, in section 4.3.4 below;
- ActewAGL Distribution's augmentation capex is not overstated, but rather is necessary to achieve the capex objectives specified in the Rules, as evidenced by the detailed project justification reports for the major augmentation projects in section 4.4.4 below;
- ActewAGL Distribution's replacement capex is not overstated, and the conclusions drawn by the AER from its historical trend analysis flawed comparative benchmarking analysis are flawed. The AER's alternative estimate for repex is based on incorrect data and flawed analysis and is therefore invalid, section 4.5.4 below.
- the AER's capitalised overhead 'adjustment factor' is inconsistent with ActewAGL Distribution's revised CAM that applies from 1 July 2014, in section 4.6.4 below; and
- ActewAGL Distribution's capex forecasts should be based on its proposed revised labour and material escalators, in section 4.7.4 below.

The AER has based its alternative forecasts for repex and capitalised overheads on an analysis of ActewAGL outcomes for this expenditure in the 2009-14 regulatory period. In this chapter, ActewAGL Distribution demonstrates that trend analysis does not provide a robust indication of future repex requirements, and that ActewAGL Distribution's forecast capitalised overheads for the 2014-19 should not be based on the proportion of overheads allocated to capex projects in the 2009-14 regulatory period because this ignores the change in ActewAGL Distribution's CAM that came into effect on 1 July 2014.

ActewAGL Distribution is also concerned by a number of discrepancies between the AER's draft decision and the AER's consolidated capex model, specifically expenditure by asset class which is an input to ActewAGL Distribution's regulated revenue in the PTRM. For example:

- The AER *'accepts that ActewAGL's forecast of ICT capex*[510] *is a reasonable estimate for the efficient costs required for this category,'*[511] but in the capex model applies a 'capex adjustment factor' that has the effect of reducing ActewAGL Distribution's IT Communication Systems (network) expenditure each year.[512] The AER's capex adjustment factor is calculated as the weighted average of the AER's cuts to connections, augmentation and replacement capex categories. The model does not provide any detail as to how the cuts to connections, augmentation and replacement capex were calculated.
- The model also applies the capex adjustment factor to ActewAGL Distribution's forecast for distribution and transmission zone substations, which would appear to be completely inconsistent with the AER's statements in the draft decision that it has reduced augmentation capex by 38 per cent by way of removing five major zone substation projects. The AER has confirmed that it applied the *'same [percentage reduction] factor across the system' rather than doing a 'bottom up build model.'*[513] This is inconsistent with the approach discussed in the draft decision which was to '*make reductions…to projects*.'[514]
- The AER in its draft decision does not comment on ActewAGL Distribution's proposed transmission capex, but in its capex model has reduced transmission network capex by a capex adjustement factor of up to 50 per cent in each year of the regulatory period.

[510] AER, 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-71. Footnote 112 states: 'This includes expenditure on both network and non-network related ICT assets, but excludes capitalised overheads.'

[511] AER, 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-72

[512] AER, 2014, *Consolidated Capex Model - ActewAGL Distribution Draft Determination 2014-19; 6. Forecast Capital Expenditure by asset class*

[513] 18 December 2014, Meeting between AER staff and ActewAGL Distribution staff

[514] For example, in the AER's discussion on augex, page 6-31 the AER states "*Based on this engineering review, we made reductions to the following projects…."*

ActewAGL Distribution advances no additional arguments or supporting material in respect of these accepted capex categories in this chapter. However, ActewAGL Distribution notes that to the extent that expenditure allowances by asset class in the AER's model are inconsistent with statements made by the AER in the draft decision, ActewAGL Distribution's expenditure by asset class over the 2014-19 period is likely to be inconsistent with the draft decision.

ActewAGL Distribution proposes a revised capex allowance of $341 million for the 2014-19 period required to achieve the capex objectives specified in clause 6.5.7(a) of the Rules. ActewAGL Distribution's revised total capex program by category is provided in Table 4.3 below.

Table 4.3 ActewAGL Distribution revised capex program 2014-19

$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
ActewAGL Distribution proposal	75.3	70.3	85.8	74.5	66.3	372.2
AER draft decision	59.2	47.8	51.8	44.8	40.6	244.2
ActewAGL Distribution's revised proposal	**74.5**	**62.6**	**71.8**	**69.0**	**63.1**	**341.0**

ActewAGL Distribution's revised capex program is $31.2 million or 8.4 per cent lower than that proposed by ActewAGL Distribution in its regulatory proposal for the subsequent regulatory period. Major variations between the two programs are:

- A reduction in augex of $17.5 million, due to revised demand forecasts which indicate that a third transformer at the Belconnen zone substation is not likely to be required during the 2014-19 regulatory period, and updated cost estimates for the Molonglo zone substation and the zone substation earth grids refurbishment project. This is discussed in section 4.4.4 of this revised proposal.
- A reduction in the total capex forecast of $5.2 million attributed to revised cost escalators. ActewAGL Distribution's response to the AER's findings on real cost escalation is provided in section 4.7.4 of this revised proposal.
- A proportionate reduction in capitalised overheads of $4.1 million associated with a reduced capital works program for the 2014/19 period than was proposed by ActewAGL Distribution in its regulatory proposal for the subsequent regulatory period.
- An increase in non-network capex of $4.2 million to reflect the corporate cost allocation associated with Operating Systems Replacement Program (OSRP) phase 2 that was omitted from the forecast of ICT expenditure and non-network capex included in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period. This omission was identified in the course of addressing the discrepancies in the forecasts of non-network capex

as between the completed RIN templates and the populated PTRM accompanying ActewAGL Distribution's regulatory proposal identified by the AER in its draft decision.

- A reduction in relocations capex of $3.1 million that should have been classified as alternative control services in ActewAGL Distribution’s regulatory proposal for the subsequent regulatory period.
- Inclusion of vehicle disposals previously omitted from ActewAGL Distribution’s regulatory proposal for the subsequent regulatory period of $2.9 million.
- Decrease in total capex of $2.5 million to reflect the adjustment in CPI between ActewAGL Distribution’s regulatory proposal for the subsequent regulatory period (3.25 per cent) and this revised proposal (2.71 per cent).

ActewAGL Distribution’s proposed revised capex of $341 million for the 2014/19 regulatory period is the amount required to achieve the capex objectives. This is supported by arguments set out in this chapter and provided in additional justification reports attached to this revised submission.

ActewAGL Distribution further observes that, despite the AER having a legislative obligation under the NEL to satisfy the National Electricity Objective (NEO) to the greatest extent possible, the AER has provided no evidence that it has assessed the impact of its draft decision on capex, to disallow 34.4 per cent of ActewAGL Distribution's proposed total capex, in combination with its draft decision on opex, to disallow 41.6 per cent of ActewAGL Distribution's proposed total opex, on the quality, safety, reliability and security of supply of electricity in the ACT. The AER does not appear to have had any regard to the economic costs and risks of the potential for under investment in the ACT electricity distribution system in making its draft decision.

ActewAGL Distribution has assessed the likely implications of the AER’s Draft decision on safety, quality, reliability and security of the network in section 2.8 and considers that the draft decision will raise the level of risk of operating the network in the period 2015-2019 so as to potentially lead to catastrophic failure of the network and endanger the safety of the public. These consequences clearly demonstrate that the AER’s draft decision is not in the long term interests of consumers, hinders, rather than contributes to, the achievement of the NEO, and does not enable ActewAGL Distribution to achieve the capex objectives.

4.2 The relevant legal and regulatory framework for setting the capex allowance

4.2.1 The NEO and the RPPs

ActewAGL Distribution refers to and repeats the discussion of the relevance and role of the NEO and the RPPs in section 3.2.1 above.

4.2.2 Constituent decision on capex

The constituent decisions on which the distribution determination for ActewAGL Distribution for the subsequent regulatory period is predicated relevantly include:[515]

- a decision on the annual revenue requirement for ActewAGL Distribution for each regulatory year of the regulatory control period to which the determination relates; and
- a decision in which the AER either accepts ActewAGL Distribution's total capex forecast for that regulatory control period or does not accept that forecast, in which case the AER must determine an estimate of ActewAGL Distribution's required capex for that period.

Clause 11.56.4(c) of the Rules provides that, for the purpose of making a distribution determination for ActewAGL Distribution for the subsequent regulatory period, the AER must determine (amongst other things) the annual revenue requirement for ActewAGL Distribution for each regulatory year of the subsequent regulatory period and its total revenue requirement for the subsequent regulatory period, as if the subsequent regulatory period comprised the transitional regulatory period and all of the regulatory years of the subsequent regulatory period and the transitional regulatory period were not a separate regulatory control period. That clause further provides, for the avoidance of doubt, that the AER must determine a notional annual revenue requirement for the regulatory year that comprises the transitional regulatory period.

The annual revenue requirement for ActewAGL Distribution for each regulatory year of the 2014-19 period must be determined using a building block approach, under which the building blocks relevantly include the forecast capex for that year as accepted or amended by the AER in making the distribution decision.[516]

4.2.3 The capex criteria, capex objectives and capex factors

The AER is required to accept ActewAGL Distribution's forecast capex where it is satisfied that the total of the forecast capex for the regulatory control period reasonably reflects the following criteria (capex criteria) in clause 6.5.7(c) of the Rules, being:

- the efficient costs of achieving the capex objectives specified in clause 6.5.7(a) of the Rules (capex objectives);
- the costs that a prudent operator would require to achieve the capex objectives; and

[515] Clause 6.12.1(2) and (3) of the Rules

[516] Clauses 6.4.3(a)(7) and (b)(7) of the Rules

- a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives.

  Similarly if the AER is not so satisfied and, accordingly, does not accept ActewAGL Distribution's forecast of required capex, the AER must estimate ActewAGL Distribution's required capex that it is satisfied reasonably reflects the capex criteria taking into account the matters specified in clause 6.5.7(e) of the Rules (capex factors) (clauses 6.5.7(d) and 6.12.1(4)(ii) of the Rules).

  The capex objectives in clause 6.5.7(a) of the Rules are to:

- meet or manage the expected demand for standard control services over the regulatory control period;
- comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
- to the extent that there is no applicable regulatory obligation or requirement in relation to:
  - the quality, reliability or security of supply of standard control services; or
  - the reliability or security of the distribution system through the supply of standard control services,

  to the relevant extent:
  - maintain the quality, reliability and security of supply of standard control services; and
  - maintain the reliability and security of the distribution system through the supply of standard control services; and
- maintain the safety of the distribution system through the supply of standard control services.

  In deciding whether or not it is satisfied that the forecast capex for the regulatory control period reasonably reflects the capex criteria, the AER must have regard to the capex factors specified in clause 6.5.7(e) of the Rules, including, relevantly:

- the most recent annual benchmarking report that has been published under clause 6.27 and the benchmark capex that would be incurred by an efficient DNSP over the relevant regulatory control period;
- the ActewAGL and expected capex of the DNSP during any preceding regulatory control periods;
- the extent to which the capex forecast includes expenditure to address the concerns of electricity consumers as identified by the DNSP in the course of its engagement with electricity consumers;
- the relative prices of operating and capital inputs;
- the substitution possibilities between opex and capex;

- whether the capex forecast is consistent with any incentive scheme or schemes that apply to the DNSP under clauses 6.5.8A or 6.6.2 to 6.6.4;
- the extent the capex forecast is referable to arrangements with a person other than the DNSP that, in the opinion of the AER, do not reflect arm's length terms;
- whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b);
- the extent the DNSP has considered, and made provision for, efficient and prudent non-network alternatives;
- any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s); and
- any other factor the AER considers relevant and which the AER has notified the DNSP in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is a capex factor.

4.3 ActewAGL Distribution's forecasting methodology

4.3.1 Overview

In its regulatory proposal for the subsequent regulatory period, ActewAGL Distribution proposed the use of a zero-based approach to forecasting capex for all capex categories other than non-network capex, for which it used a combination of zero-based and base year approaches. ActewAGL Distribution's zero-based approach involves a bottom-up construction of capex associated with projects.

In its draft decision, the AER concludes that two aspects of ActewAGL Distribution's forecasting methodology render that methodology insufficient to found a conclusion that ActewAGL Distribution's resultant total capex forecast reasonably reflects the capex criteria. These are as follows:[517]

- first, ActewAGL Distribution's forecasting methodology applies a bottom-up build to forecast capex for all capex categories other than ICT capex in the non-network capex category but does not apply a top-down assessment; and
- secondly, ActewAGL Distribution's risk assessment underlying its evaluation of projects in performing its bottom-up build is overly conservative.

[517] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, pp. 6-19 to 6-20

While ActewAGL Distribution predominantly employed a zero-based approach (that is, a bottom up build) to preparing its total capex forecast included in its regulatory proposal for the subsequent regulatory period, ActewAGL Distribution:

- assessed its proposed forecast of total capex, derived using its zero-based approach, by means of top down techniques to ensure those forecasts did not overstate required allowances in that they adequately accounted for inter-relationships and synergies between projects or areas of work before submitting that proposal to the AER; and
- now adduces this top down analysis in support of the efficiency of that forecast.

This is discussed further in section 4.3.4 below.

ActewAGL Distribution rejects the AER's conclusion that its evaluation of capex projects and programs is 'overly conservative'. ActewAGL Distribution uses a network planning methodology that combines probabilistic criteria which incorporates risk parameters and deterministic measures to optimize the trade-off between network investment and minutes off supply. Indeed, Jacobs has compared ActewAGL Distribution’s network planning criteria to those of other DNSPs and TNSPs in the NEM and has concluded that they are *not* 'overly conservative'. This is discussed further in section 4.3.4 below.

4.3.2 ActewAGL Distribution's proposal

ActewAGL Distribution submitted its expenditure forecasting methodology to the AER on 30 November 2013 in accordance with clauses 6.8.1A(a) and 11.56.4(o) of the Rules. This was re-submitted to the AER along with its regulatory proposal for the subsequent regulatory period on 2 June 2014.[518] This document set out at a high level the forecasting methods (zero-based and base year) and systems (asset management systems and RivaDS) used by ActewAGL Distribution to establish potential capex and opex programs for the 2014-19 period, and to a certain extent, prioritise projects within each program.

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[518] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), Attachment B19 (ActewAGL Distribution Expenditure Forecasting Methodology (May 2014))

ActewAGL Distribution capex categories are asset renewal and replacement, augmentation capex, reliability and quality improvements, customer initiated capex, non-network capex and network OT.[519]

ActewAGL Distribution uses a zero-based approach to forecasting capex for all categories other than non-network capex, for which it used a combination of zero-based and base year approaches.[520]

ActewAGL Distribution's zero-based approach involves a bottom-up construction of capex associated with projects. The unit rates used by ActewAGL Distribution in constructing project costs are detailed in individual project justifications and asset management plans and were independently reviewed by SKM (now Jacobs) who concluded that ActewAGL Distribution's activity unit rate estimates are reasonable and efficient.[521] Expenditure forecasts are then escalated for the 2014-19 period in line with material and labour cost escalators independently developed and/or verified by SKM, CEG and Independent Economics.[522]

In 2012, ActewAGL Distribution implemented RivaDS, a real time, web based software tool that supports long range asset management planning and decision making by bringing together asset data from various sources within ActewAGL Distribution including spatial, work management and financial systems. RivaDS produces individually optimised maintenance and refurbishment plans and associated life cycle expenditure forecasts for each asset class, and these form the basis of

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[519] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 161-162

[520] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 162 and Attachment B19 (ActewAGL Distribution Expenditure Forecasting Methodology (May 2014). pp. 13-15.

[521] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 162-163 and Attachment B11 (Unit rates - SKM Independent Verification Report)

[522] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 163-166 and Attachment B11 (Unit rates - SKM Independent Verification Report), Attachment B12 (Cost escalation report - CEG) and Attachment B13 (Cost escalation report - Independent Economics)

ActewAGL Distribution's capex forecasts in its regulatory proposal for the subsequent regulatory period.[523]

4.3.3 AER's draft decision

The AER concludes that two aspects of ActewAGL Distribution's forecasting methodology render that methodology insufficient to found a conclusion that ActewAGL Distribution's resultant total capex forecast reasonably reflects the capex criteria. These are as follows:[524]

- first, ActewAGL Distribution's forecasting methodology applies a bottom-up build to forecast capex for all capex categories other than ICT capex in the non-network capex category but does not apply a top-down assessment; and
- secondly, ActewAGL Distribution's underlying risk assessment is overly conservative.

The AER concludes in respect of bottom up techniques that:[525]

In our view, applying a top-down assessment is a critical part of the process in deriving a forecast capex allowance. It indicates that some level of overall restraint that [sic] has been brought to bear. This is an important factor for us to consider in deciding whether we are satisfied that a proposed forecast capex allowance reasonably reflects the capex criteria. In particular, to derive an estimate of capex by solely applying a bottom-up assessment does not itself provide any evidence that the estimate is efficient. Bottom-up assessments have a tendency to overstate required allowances as they do not adequately account for inter-relationships and synergies between projects or areas of work which are more readily identified at a portfolio level. Whereas reviewing aggregated areas of expenditure or the total expenditure, allows for an overall assessment of efficiency [sic]. Whilst in certain very limited circumstances, a bottom up build may be a reasonable approach to justifying expenditure, this is not the case when looking at aggregated areas of expenditure or at the portfolio level. However, [sic] simply aggregating estimates is unlikely to result in a total forecast capex allowance that we are satisfied reasonably reflects the capex criteria.

In respect of top down assessment techniques, the AER concludes:[526]

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[523] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 163

[524] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, pp. 6-19 to 6-20

[525] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-19

…trend analysis is a top-down assessment that can be applied in the context of a distribution network. This technique is able to test whether an estimate that results from a bottom-up assessment might be efficient…

A top-down assessment should also clearly evidence a holistic and strategic consideration or assessment of the entire forecast capex program at a portfolio level. It should also demonstrate how the forecast capex proposal has been subject to governance and risk management arrangements. In turn, these arrangements should demonstrate how the timing and prioritisation of certain capital projects or programs has been determined over both the short and long-term. It should also demonstrate that capex drivers, such as asset health and risk levels, are well defined and justified. In particular, asset health and risk level metrics are key elements of capex drivers.

ActewAGL's forecast methodology does not demonstrate any of these points (except for non-network assets).

The range of assessment techniques available to us provides for a top-down assessment. These techniques enable us to test whether an estimate that results from a bottom-up assessment might be efficient.

With respect to the conservatism of ActewAGL Distribution's underlying risk assessment, the AER concludes:[527]

…ActewAGL Distribution's cost-benefit evaluation of each of its capital projects or programs reveals that its underlying risk assessment is overly conservative. The focus is on reducing its business risks instead of risks to consumers. This is evident in ActewAGL's failure to fully justify the timing and priority of its proposed forecast capex. Ultimately, this overly conservative approach to risk means that ActewAGL is forecasting more capex in the 2014-2019 period than is necessary to achieve the capex objectives. In particular, ActewAGL does not demonstrate that it has properly considered the extent to which its programs or projects can be deferred to the 2020-2025 regulatory control period. An overly conservative risk approach is likely to result in a forecast capex allowance that is greater than what is required to achieve the capex objectives.

4.3.4 ActewAGL Distribution's response

ActewAGL Distribution considers the AER's adverse conclusions regarding its forecasting methodology are unfounded. It asserts that, in preparing its capex forecasts proposed in its

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[526] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-20

[527] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-20

regulatory proposal for the subsequent regulatory period, it did apply top down assessment techniques and rejects the notion that the risk assessment underlying those forecasts is 'overly conservative'. It addresses each of the AER's adverse conclusions in greater detail in turn below.

ActewAGL Distribution's application of top down assessment techniques

ActewAGL Distribution observes, at the outset, that the AER's propositions that *'to derive an estimate of capex by solely applying a bottom-up assessment does not itself provide* any *evidence that the estimate is efficient'* (emphasis added) and that the use of a bottom up approach to forecasting and justifying expenditure will be a reasonable approach only in *'very limited circumstances'* are startling.

First, top down assessment techniques, such as trend analysis, that rely on historic expenditure are likely to provide limited evidence of the efficiency of forecast capex given the generally non-recurrent and lumpy nature of capex, particularly for augmentation expenditure rendering the economic justification for individual projects and work areas that underlies a bottom up build critical to assessing efficiency.

Secondly, these views cannot be readily reconciled with the AER's recognition, in its *Expenditure Forecast Assessment Guideline*, of the significance of economic justifications for individual projects or areas of work to the justification and assessment of the efficiency of capex programs and forecasts. Specifically, in that Guideline, the AER states in respect of its capex assessment approach:

We will generally assess forecast capex through assessing: the need for the expenditure; and the efficiency of the proposed projects and related expenditure to meet any justified expenditure need. This is likely to include consideration of the timing, scope, scale and level of expenditure associated with proposed projects. Where businesses do not provide sufficient economic justification for their proposed expenditure, we will determine what we consider to be the efficient and prudent level of forecast capex.[528]

Thirdly, the AER's focus on top down techniques that rely on ActewAGL Distribution's historic capex to forecast and assess the efficiency of capex cannot be reconciled with its opex draft decision, implicit in which is a conclusion that ActewAGL Distribution did not respond to the incentives for efficiency created by the regulatory regime in incurring expenditure in the 2009/10 to 2013/14 regulatory control period (even in incurring opex for which there were the enhanced incentives created by the EBSS). Where the AER maintains its opex draft decision in making its final determination, limited probative weight can reasonably be accorded to trend analysis,

[528] AER, 2013, *Expenditure Forecast and Assessment Guidelines for Electricity Distribution*, p. 24

particularly given that no efficiency incentive scheme in respect of capex applied to ActewAGL Distribution in the 2009/10 to 2013/14 and previous periods.

In light of this, notwithstanding the express indications to the contrary in the draft decision, ActewAGL Distribution does not understand the AER to be suggesting that it should have used a top-down approach to forecasting capex for all capex categories to the exclusion of its zero-based approach. Rather, ActewAGL Distribution understands the AER to be suggesting that it should have:

- assessed the capex forecasts it derived using its zero-based approach by means of top down techniques to ensure those forecasts did not overstate required allowances in that they adequately accounted for inter-relationships and synergies between projects or areas of work; and
- adduced this top down analysis to justify the efficiency of those forecasts.

While ActewAGL Distribution predominantly employed a zero-based approach (that is, a bottom up build) to preparing its total capex forecast included in its regulatory proposal for the subsequent regulatory period, ActewAGL Distribution undertook just such a top-down assessment of its total capex forecast before submitting that proposal to the AER.

Specifically, ActewAGL Distribution undertook an assessment of total system expenditure, which incorporates many aspects of the 'top-down assessment' methodology referred to by the AER, before submitting that proposal to the AER. The objective of ActewAGL Distribution's top-down assessment process was to ensure the capex program was not overstated, and that it is efficient from an overall perspective. This was achieved by:

- undertaking a trend analysis against expenditure in past regulatory periods;
- considering all potential capex-opex trade-offs;
- applying appropriate capital governance and risk management procedures; and
- ensuring expenditure forecasts suffice to meet all relevant regulatory requirements.

Overall expenditure was kept within an acceptable envelope, based on expenditure in previous years, the overall condition of assets, safety and other regulatory obligations and risk management of security of supply. The application by ActewAGL Distribution of these top down assessment techniques also ensures that its zero-based approach to preparing its capex forecasts did not over-state required allowances and ensured that those forecasts adequately accounted for inter-relationships and synergies between projects or areas of work.

For example, the initial top-down analysis highlighted a number of assets that have been in service for many years, have exceeded their expected economic life and are due for replacement or refurbishment. This presents 'spikes' in forecast expenditure that are typically managed in one of the following ways:

- Conduct a risk assessment on assets overdue for replacement/refurbishment based on the consequence of failure. Depending on the outcome of this assessment, expenditure may be deferred. This strategy was recently applied to ActewAGL Distribution's aging power transformers at Gilmore and Theodore zone substations. Although these 48 year old transformers are past their economic life (45 years), ActewAGL is monitoring the expected remaining life of these assets with oil sample analysis, and will undertake further invasive testing of the state of the insulating paper within the transformer coils to ensure maximum use is made of these assets before they are refurbished or replaced.
- Identify any synergies between asset class forecasts such that assets overdue for replacement or refurbishment can potentially be provided with sufficient backup or redundancy by new projects that are 'in the pipeline'. For example the Molonglo zone substation was deferred from the 2009-14 regulatory period by utilising feeders from nearby zone substations.
- Consider alternative maintenance strategies, such as applying condition monitoring technology to more fully assess the risk of failure, and determine if refurbishment or replacement may be deferred. ActewAGL Distribution is currently using sophisticated timing and resistance measuring instruments to more accurately determine the condition of aging zone substation circuit breakers.

Each of the steps in ActewAGL Distribution's top-down assessment process is detailed, in turn, below.

Trend analysis

ActewAGL Distribution has assessed the reasonableness of its forecasts against expenditure in past periods, including an assessment of any historical anomalies or abnormal practices. This is a lengthy and iterative process to ensure that all of the following trends have been considered in formulating ActewAGL Distribution's total capex program:

- the optimum timing of high value augmentation projects to meet stakeholder expectations, and constrain the volatility of expenditure on a year to year basis;
- confidence levels of customer initiated and government development project forecasts;
- forecast economic growth;
- long term strategic trends within the industry; and
- emerging technologies.

The Molonglo zone substation project justification report (PJR) provides an indication of the detailed trend analysis undertaken on a project by project basis during ActewAGL Distribution's top-down forecasting assessment. Specifically, this included:

- reference to updated forecast dwelling occupation information provided annually by the ACT Land Development Agency;

- moderation of forecast dwelling electricity demand based on the historical trend of similar land releases;
- the use of lower dwelling occupation electricity demand based on known industry trends for residential demand management initiatives lowering the nominal electricity demand per residence; and
- consideration of capacity and infrastructure at adjacent zone substations to provide the initial electricity supply to the Molonglo District.

Capex/Opex trade-offs

The consideration of capex-opex trade-offs within ActewAGL Distribution's total capex forecast is a key component of ActewAGL Distribution's top-down assessment process. The required trade-off analysis is usually undertaken with respect to refurbishment and replacement of aging and potentially unreliable equipment, where the ongoing maintenance, repair, and fault costs (including loss of supply) can be compared with the capital cost of refurbishment and replacement.

An example of a capex-opex trade-off evaluation undertaken in preparing the capex forecasts for the 2014-19 period is that relating to ActewAGL Distribution's decision to install fibreglass poles in 'back yards' instead of wood poles to reduce life cycle costs of maintenance of those assets. This analysis was provided to the AER as attachment B17.1 to ActewAGL Distribution's subsequent regulatory period. The majority of capex-opex trade-off evaluations are not assessed on a project by project basis, but on an asset class basis, and ActewAGL Distribution referred to several examples of these evaluations in its regulatory proposal for the subsequent regulatory period and attachment B.17.1. These included the pole replacement program, the underground cable replacement program[529] and replacement of the ageing Civic switchboard during the 2009-14 regulatory period.[530]

ActewAGL Distribution uses a risk based decision support model, "*Analysed Program of Works*", to optimise its five year asset renewal and replacement capex program and to make capex/opex trade-off evaluations. In particular, this model considers the failure effect and risk (likelihood and consequence) of each investment decision. Failure effect can include impacts on safety of

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[529] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p.173 (underground cable replacement) and p.171 (pole replacement).

[530] JacobsSKM 2014, *Capex/Opex trade-off Issue,* 26 May 2014, (Attachment B 17.1) p.6.

personnel and public, impact on environment, cascading failure on other equipment, operational consequences (unserved energy), and risk to reputation.

Based on the determined failure effect for each asset under consideration, one of the following replacement strategies is adopted and an optimal time for replacement or monitoring is identified:

- run to failure;
- condition monitoring; or
- age and condition based replacement.

The methodology described for the *Analysed Program of Works* model was used to prioritise ActewAGL Distribution's replacement capex and to establish non-discretionary and discretionary replacement capex budgets that form the basis of capex forecasts contained in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period.

In setting ActewAGL Distribution's maintenance program, the selection of a run to failure, replace on condition or replace on age or usage strategy will be dependent on the safety implications of each and which strategy has the lowest overall expected cost. Generally, replace on condition is the most relevant to capex/opex trade off decisions and is most commonly employed where the consequence of failure is very high, for example pole failures. Where the consequence of failure is low such as assets with standby capacity, the run to failure strategy is often the least cost option. Most distribution transformers have adjacent units which can take up the load in event of failure, so it is common to run these units to failure. The run to failure strategy has the advantage of delivering the maximum life from an asset, however once failure has occurred, replacement or repair is no longer discretionary. Age or usage based replacement is used where inspections are costly, and/or the asset cannot be allowed to run to failure because of safety reasons. An example of this is ActewAGL Distribution's earth grid upgrade project discussed in section 4.4.4 below.

Governance of Capital Investment Projects

The AER stated that ActewAGL Distribution should demonstrate how the forecast capex proposal has been subject to governance and risk management arrangements. This information, along with examples of where these top-down assessment techniques have been applied, are detailed in ActewAGL Distribution's 3 October 2014 submission to the AER.[531]

[531] ActewAGL Distribution, 2014, *Operating and capital expenditure 'site visit' clarifications, 2014-19 subsequent regulatory control period*, 3 October 2014. This document was submitted to the AER in response to an

Capex proposals generated by asset managers are coordinated through an asset management systems group before being advanced through the General Manager – Asset Management for consideration by the executive. Broad adjustments as directed by the executive are fed back to asset managers for further refinement. The process is repeated until an acceptable solution is arrived at. These controls are described in ActewAGL Distribution's Asset Management System – Governance Framework Version 1.0 and Asset Management Strategy Version 2.11.532 This strategy is provided as Attachment D1 to this submission.

ActewAGL Distribution has a corporate investment framework including corporate policies, delegations manual and planning / approvals processes to ensure that capital investment has an effective governance, prudency and efficiency framework. There are two approaches adopted by ActewAGL Distribution to manage capital investment: one is an existing framework for managing minor or less complex capital investment with delegation levels, investment and accountability for decision making. The second is the use of Project Boards for larger, more complex capital projects.

There is a delegation manual with authorisations specific to capex and maintenance. Key documents that set out the governance and approvals framework for capex are:

- *ActewAGL Distribution Corporate procedure - Delegations of authority; and*
- *Asset Management Commercial Risk Framework Policy ‐ Expenditure.*

These are provided as Attachments D2 and D3 to this revised proposal.

The ActewAGL Distribution Board approves expenditure (and is responsible for release of funds) based on business cases with a capital value in excess of $5.5 million.

ActewAGL Distribution established Project Boards and project management best practices based on PRINCE2 methodology for prudency, efficiency and the governance of major projects. Key stakeholders are brought together under the umbrella of the Project Board to make decisions as a group, thereby ensuring the needs of key stakeholders are met and the delays associated with serial or multi-layered decision-making are overcome. This is in keeping with current good practice in capital project governance.

ActewAGL Distribution has recently implemented the transition of a number of legacy ICT and Network OT systems (non-network capex) programs under the "Operational Systems Replacement (OSR) Program" using the Project Board governance framework. In addition,

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information request by the AER dated 17 September 2014 the intent of which was to seek clarification on opex and capex issues discussed at a meeting between AER and ActewAGL Distribution staff on 16 September 2014.

ActewAGL Distribution has adopted the PRINCE2 project management methodology, and has trained a number of staff as PRINCE2 practitioners. The project delivery function has also been improved with the introduction of portfolio managers and end to end definition of responsibilities and governance.

Regulatory obligations and requirements

In formulating its capex program, ActewAGL Distribution must ensure that forecast capex is adequate to enable it to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services. Key regulatory obligations and requirements relevant to the provision of standard control services were summarised in Chapter 4 of ActewAGL Distribution's regulatory proposal for the subsequent regulatory period. Of particular importance are ActewAGL Distribution's responsibilities under the Work Health Safety Act 2011 and the Utilities Act. Details of relevant regulatory obligations and requirements are provided in project justification reports in respect of major capex projects.

ActewAGL Distribution's network planning criteria is not overly conservative

ActewAGL Distribution strongly rejects the AER's view that its network planning criteria are overly conservative. In planning the augmentation of its electricity distribution and transmission networks, ActewAGL Distribution uses a mixture of deterministic (rule based) criteria and probabilistic criteria as outlined in section 6.5 of ActewAGL Distribution's regulatory proposal for the subsequent regulatory period. Both ActewAGL Distribution's deterministic and its probabilistic planning criteria incorporate risk parameters.

In concluding that ActewAGL Distribution's cost-benefit evaluation of augmentation capex programs and projects is 'overly conservative', the AER refers to only a section of ActewAGL Distribution's planning criteria in its draft decision, which section, if considered in isolation from the remainder of those planning criteria, could be construed as suggesting that the risk to security and reliability of supply is not taken into account.[533] However, the risks of customer outages and unserved energy are inherently being taken into account through the application of its network planning criteria, without the need for the performance of discrete unserved energy calculations using VCR estimates. For example;

- ActewAGL Distribution uses 10 per cent POE demand forecasting combined with a 2 hour emergency rating of zone substation transformers as the basis of exceedance before a network constraint is identified; and

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[533] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-34.

- In allocating forecast demand, ActewAGL Distribution typically assumes a probabili8ty factor of 100 percent for consumer connections supported by a connection application, a probability factor of between 30 per cent and 80 per cent for consumer connections supported by a connection enquiry, and a probability factor of between 0 per cent and 50 per cent for other potential consumer loads that ActewAGL distribution are aware of, for example, through its routine consultation with ACT Government departments.

ActewAGL Distribution engaged Jacobs to review the AER's comments on ActewAGL Distribution's network planning criteria. Jacobs' report[534] is attached as Attachment D4 to this revised regulatory proposal and the key findings of that report are detailed below.

Jacobs compared ActewAGL Distribution's criteria to those of other DNSPs and TNSPs in the NEM. For transmission lines (132kV), Jacobs found ActewAGL Distribution's criteria to be at the 'upper end' of emergency ratings, but not 'overly' conservative. Furthermore, Jacobs found ActewAGL Distribution's standards entirely appropriate for the Southern Supply to ACT – Stage 2 project. The purpose of this project is to reinforce the capacity of the ActewAGL 132kV transmission system such that it can be used, not only to supply the load within the ACT, but also to provide mutual back-up 132kV tie capacity to TransGrid's 330/132kV Canberra and Williamsdale substations. By reinforcing its 132kV transmission system and adopting the emergency ratings for transmission lines that it has, ActewAGL has effectively deferred the cost of more expensive TransGrid transmission augmentation work into future years.

In respect of ActewAGL Distribution's system security and planning criteria for the primary distribution system (11 kV and 22 kV), Jacobs concluded that this is similar to that of other DNSPs in the NEM, with distribution feeders being loaded up to 75 per cent of their thermal rating depending on the number of inter-feeder ties available. Jacobs also found that ActewAGL Distribution's zone substation loading methodology, described below is not 'overly conservative.'

ActewAGL Distribution uses the more onerous two hour emergency cyclic rating for all its zone substation power transformers, even though it does not currently hold a system spare power transformer.

ActewAGL Distribution maintains a high level of zone transformer utilisation through the adoption of the two hour emergency rating, and effective load balancing between zone substations wherever possible. The load balancing is an integral initial solution as part of network augmentation planning. During the 2009-14 regulatory control period, a conscious decision was made to install just a single transformer in the new East Lake zone substation, and operational plans were developed to enable East Lake, Fyshwick, and Telopea Park zone substations to be operated on a "combined N-1 basis."

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[534] Jacobs 2014, *Review of AER Draft Decision – Augex*, December 2014

This means that instead of each zone substation being operated individually on an N-1 basis, as a combined group they are operated such that the loss of any one of the total of seven transformers (a significantly increased risk) can be covered by load transfers on the 11kV distribution system. Depending on which transformer fails, some load may be lost initially, but is able to be restored with manual switching. This approach simply does not support the AER's finding that ActewAGL Distribution has used "*overly conservative criteria when making augmentation decisions on zone substations*."[535]

4.4 Augmentation capex

4.4.1 Overview

In its draft decision, the AER did not accept ActewAGL Distribution's proposed augmentation capex of $99.5 million ($2013/14) excluding overheads. It instead included augmentation capex of $61.7 million ($2013/14) excluding overheads in its alternative estimate of total capex, representing a reduction to ActewAGL Distribution's augex proposal of 38 percent.

The AER's draft decision on augex was based on trend analysis, an examination of utilisation and capacity on ActewAGL Distribution's network, an assessment of ActewAGL Distribution's augmentation planning criteria and an engineering review of ActewAGL Distribution's major augex projects. In summary, on the basis of this assessment, the AER concluded that:

- there is likely to be excess capacity in the network that could be utilised ahead of additional augmentation investment;
- ActewAGL Distribution has used overly conservative criteria in making augmentation decisions on zone substations and proposed VCRs in its regulatory proposal for the subsequent regulatory period that, if used as an input to its augmentation planning, would have resulted in the overstatement of required augmentation capex; and
- ActewAGL Distribution's proposed capex for the 5 major augmentation projects that were the subject of the AER's engineering review, being the new Molonglo zone substation, the installation of a third transformer at Belconnen zone substation, the zone substation earth grid upgrade, the Gold Creek 11kV switchboard extension and capex on the future Mitchell zone substation, should be significantly reduced, primarily because the AER considered ActewAGL Distribution did not adduce sufficient evidence in respect of project evaluation, justification and timing.

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[535] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-30.

ActewAGL rejects the notion that there is excess capacity on its network capable of being utilised ahead of additional augmentation investment. The AER's conclusion to the contrary would appear to be based on a 'desktop' assessment of average utilisation of zone substations. This analysis would appear to contain a deficiency that results in the overstatement of excess capacity and is inadequate, in any event, to support any conclusion about the technical and economic feasibility of meeting a demand constraint at any given point on the network with excess capacity. Rather, the detailed project justification reports for each of the major augmentation projects proposed by ActewAGL Distribution that are attached to this revised regulatory proposal disclose that, in respect of these projects, this is not technically and economically feasible. This is discussed further in section 4.4.4 below.

ActewAGL Distribution rejects the AER's conclusion that its evaluation of capex projects and programs is 'overly conservative.' The combination of deterministic and probabilistic criteria that comprise ActewAGL Distribution's network planning criteria incorporate risk parameters, with the consequence that the risks of customer outages and unserved energy are inherently being taken into account through the application of its network planning criteria, without the need for the performance of discrete unserved energy calculations using value of customer reliability (**VCR**) estimates. Indeed, Jacobs has compared ActewAGL Distribution's network planning criteria to those of other DNSPs and TNSPs and has concluded that they are *not* 'overly conservative'. This has already been addressed in section 4.3.4 above.

Finally, the detailed project justification reports for those projects that were subject to the AER's engineering review that are attached to this revised regulatory proposal suffice to address the AER's identified concerns with respect to their evaluation, justification and timing. ActewAGL Distribution's response to the AER's engineering review is set out in section 4.4.4 below.

4.4.2 ActewAGL Distribution's proposal

ActewAGL Distribution proposed augmentation capex for the 2014-19 period of $104.3 million,[536] or $99.5 million, excluding overheads.

ActewAGL Distribution's proposed augmentation plan for the 2014–19 period reflects the continuation of important augmentation capex that was commenced in the 2009–14 regulatory

[536] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p.159.

control period following a sustained period of very low investment.[537] Since the early 1990s, ActewAGL Distribution has built just one major new zone substation, the East Lake zone substation which was commissioned in late 2013.

The augmentation capex forecast for the 2014-19 period will ensure that ActewAGL Distribution can continue to comply with reliability standards and efficiently meet anticipated customer demand in new urban areas. Major augmentation projects included in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period are:[538]

- a new zone substation[539] in the Molonglo district for the provision of power to new suburbs in Molonglo and North Weston. The new zone substation will enable network load balancing through the transfer of some load in Weston Creek currently supplied by the Woden zone substation, thereby deferring the need for capacity augmentation at the Woden zone substation;
- installation of a 3rd 132/11 kV transformer at the Belconnen Zone Substation to meet new block loads and manage ongoing reliability in the Belconnen region. This project has been removed from ActewAGL Distribution's revised proposal on the basis of updated demand forecasts which indicate the project is unlikely to be required during the 2014-19 regulatory period; and
- upgrade of the 132 kV transmission line between Gilmore and Theodore zone substation, known as Southern Supply to ACT- Stage 2. This is a network security project aimed at upgrading existing lines to meet a capacity rating required by the *Electricity Transmission Regulation 2006* and will increase security of supply to the ACT, through mitigating a single point of failure in the network.

[537] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 183

[538] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 183

[539] Construction of the Molonglo zone substation was originally planned for the 2009–14 regulatory control period but was deferred due to deferred urban development in the areas to be serviced by this zone substation.

In addition to these projects, ActewAGL Distribution proposed several other augmentation capex projects for the 2014-19 period including:[540]

- an upgrade of zone substation earth grids to be conducted over the period 2014 to 2018, with approximately 3 substations to be upgraded per annum;
- the installation of a provisional zone substation power transformer;
- extension of the switchboards at the Gold Creek zone substation to accommodate customer connections driven by demand growth and new block loads in Gungahlin and Mitchell;
- purchase of a site for the future Mitchell zone substation;
- a number of HV feeder projects to cater for local area load growth or strengthen inter-zone ties and rebalance and optimize zone substation loading into the future; and
- the installation of NEM compliant transmission connection point metering.

4.4.3 AER's draft decision

In its draft decision, the AER did not accept ActewAGL Distribution's proposed augmentation capex of $99.5 million excluding overheads.[541] The AER instead included capex in the amount of $61.7 million (excluding overheads) in its alternative estimate of total capex, representing a reduction of 38 per cent.

The AER concluded that ActewAGL Distribution's proposed forecast of augmentation capex exceeded the augmentation capex required to achieve the capex objectives.[542] The AER based this conclusion on trend analysis, an examination of utilisation and capacity on ActewAGL Distribution's network, an assessment of ActewAGL Distribution's augmentation planning criteria (which it concluded were 'overly conservative') and an engineering review of ActewAGL Distribution's major augex projects.[543]

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[540] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 185-188

[541] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-10 and *Appendix A*, p. 6-30

[542] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-10 and *Appendix A*, p. 6-30

[543] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-30 to 6-31

The AER's trend analysis compared ActewAGL Distribution's proposed augmentation capex to its historic expenditure, taking into account changes in demand, network capacity and design and planning standards.[544] The AER concluded that that analysis shows that ActewAGL Distribution has proposed *'a slight increase'* in augmentation capex for 2014-19 in comparison to that incurred during the 2009-14 regulatory control period. In addition, it examined the utilisation of ActewAGL Distribution's network during 2009-14 and found that network utilisation did not fall significantly in the 2009-14 regulatory control period (and, indeed, average utilisation actually rose slightly for HV feeders) but that there is likely to be excess capacity in the network that could be utilised ahead of additional augmentation investment.

In respect of the planning criteria used by ActewAGL Distribution in making augmentation decisions, the AER concludes as follows:[545]

It appears that ActewAGL Distribution has used overly conservative criteria when making augmentation decisions on zone substations. In our view, this has affected the scope and unnecessarily advanced the timing of projects. For example, clause 6.2.2 of ActewAGL's distribution network augmentation standard states:

Zone substation capacity must be augmented if the forecast zone substation maximum demand based on 10% PoE under N-1 conditions is to exceed the two-hour emergency rating.

Major zone substation augmentation such as installation of additional transformer will not be considered unless other constraints that limit the transformer loading are removed.

That is, ActewAGL augments zone substations when it expects maximum demand 10 per cent POE forecast to exceed the substation's two hour emergency rating.

These criteria do not incorporate the change in the ACT Electricity Distribution Supply Standards Code (2013), which removed the requirement on supply capacity. The criteria also do not provide an assessment framework for evaluating and managing risks associated with expected unserved energy. Instead, the criteria require network capacity to fully meet expected maximum demand with no cost benefit assessment.

The AER further concludes that ActewAGL Distribution proposed VCRs in its regulatory proposal that are higher than the most current values, derived using robust and transparent methods, that were published by AEMO for NSW (including the ACT) in September 2014 and that, if these

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[544] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-30 to 6-34

[545] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-34

higher proposed VCRs were used by ActewAGL Distribution as an input to its augmentation planning, its augmentation capex forecast would be overstated.[546] The AER did not use AEMO's lower VCRs to further reduce ActewAGL Distribution's proposed forecast of augmentation capex, as it was uncertain whether ActewAGL Distribution had used its proposed VCRs in forecasting augmentation capex, but stated that it expected ActewAGL Distribution to identify the impact of AEMO's lower VCRs on its augmentation capex forecast in this revised regulatory proposal.

The AER conducted an internal engineering review of 5 of ActewAGL Distribution's major augmentation projects, being the new Molonglo zone substation, the installation of a third transformer at Belconnen zone substation, the zone substation earth grid upgrade, the Gold Creek 11kV switchboard extension and capex on the future Mitchell zone substation. In a letter to ActewAGL Distribution dated 8 December 2014, the AER stated, in response to ActewAGL Distribution's letter of 5 December 2014 requesting the AER provide it with all material relating to the engineering review of ActewAGL Distribution's proposed augmentation capex projects, that '*the draft decision reflects all calculations and analysis arising from its engineering review*'.[547]

In respect of the new Molonglo zone substation, the AER acknowledges, in its draft decision, the potential growth in the Molonglo Valley area and that ActewAGL Distribution would have to service that growth but concludes that ActewAGL Distribution did not provide sufficient evidence that its proposed Molonglo Valley substation is the efficient solution.[548] In particular, the AER concluded that:[549]

- ActewAGL Distribution's risk and options analysis is inadequate;
- ActewAGL Distribution did not adequately justify the timing of the project; and
- the project costs are high and incorporate inefficient practices.

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[546] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-34 to 6-35

[547] Letter from Usman Saadat, Manager Regulatory Affairs of ActewAGL Distribution to Mr Warwick Anderson, General Manager Network Regulation of the AER dated 5 December 2014 and email of response from Kurt Stevens of the AER to Bjorn Tibell, Senior Financial Advisor of ActewAGL Distribution dated 10 December 2014.

[548] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-36

[549] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-38

It reaches these conclusions because:[550]

- ActewAGL Distribution did not provide any details of the intangible benefits on the basis of which it preferred the project to the one other option considered, notwithstanding that that other option had a lower net present cost;
- if ActewAGL Distribution used its proposed VCRs in that analysis, the benefits identified by its options analysis may be overstated;
- ActewAGL Distribution's options analysis did not include any assessment of the 'do nothing' option or non-network solutions, which may contribute to the deferment of expenditure for a major zone substation such as that proposed;
- ActewAGL Distribution did not sufficiently investigate distribution feeder augmentation solutions from the Woden zone substation, which would potentially provide a more efficient solution;
- it is unclear from ActewAGL Distribution's documentation whether, in developing demand forecasts relevant to this project, it considered the time lag between the year(s) of land release and the year(s) when land is fully occupied and expected load eventuates which can be several years;
- ActewAGL Distribution did not present any analysis of the probability that demand may exceed existing capacity and the associated cost of unserved energy; and
- ActewAGL Distribution's proposed risk allowance to manage the uncertainty associated with the forecast cost of the project of $3.99 million is not appropriate because ActewAGL costs may be higher or lower than forecast and its proposed internal management costs for the project of $2.63 million are *'at the very high end of the normal range for project management'*.

In respect of the proposed installation of a third transformer at the Belconnen zone substation, the AER concludes that there is no justification for this project before 2023 because:[551]

- ActewAGL Distribution used an out-dated substation emergency rating to justify the need for this project; and
- ActewAGL Distribution has not demonstrated it performed adequate risk and options analysis in respect of this project in that:

[550] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-37 to 6-38

[551] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-38 to 6-40

- while it states that there are constraints on its ability to transfer load to other zone substations to cope with major transformer failure at the Belconnen zone substation, it is unclear why it did not consider additional feeders and feeder ties from Latham zone substation which has substantial spare capacity over the next 10 years and is only 3.5 km away; and
- following the removal of the capacity requirement from the Supply Standards Code, ActewAGL Distribution is not required to provide capacity to meet anticipated maximum demand and, accordingly, should have estimated the probability and cost of load curtailment in the event of capacity shortage so as to determine on the most economical solution to balance the supply risks and costs at the Belconnen zone substation.

In respect of the zone substation earth grid upgrade, the AER concludes that the failure by ActewAGL Distribution to provide any evidence of earth grid failures or degradation of performance suggests that there are no immediate or material issues with the overall condition and performance of these assets and that forecast capex should not be allowed where, as in respect of this upgrade, there is no certainty as to the need for expenditure or scope.[552]

In respect of the Gold Creek 11 kV switchboard extension, the AER concludes that the proposed capex is not prudent because ActewAGL Distribution did not explain why it had not investigated the following alternative solutions:[553]

- the common industry practice of doubling up the cable termination box on the existing switchboard where, as here, a substation does not have spare switch bays for connection of new feeders, so as to provide an additional connection terminal for new feeders at comparatively low cost; and
- distribution feeder reconfiguration and load transfers to free up the Gold Creek Substation's existing feeders or feeder bays, which on current substation maximum demand would appear to have substantial spare capacity, for potential new load in coming years.

Finally, in respect of ActewAGL Distribution's proposed forecast capex for the future Mitchell zone substation, the AER concluded that this expenditure should be disallowed because

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[552] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-40

[553] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-40 to 6-41

ActewAGL Distribution did not provide any information on the purpose and scope of the expenditure.[554]

Based on the AER's internal engineering review, the AER made reductions to ActewAGL Distribution's forecast capex (inclusive of overheads) as follows:[555]

- Molonglo zone substation and associated feeders, a reduction of $24.6 million;
- Belconnen zone substation, a reduction of $12.7 million;
- Zone substation earth grid upgrade, a reduction of $2.619 million;
- Gold Creek 11kV switchboard extension, a reduction of $0.77 million; and
- Mitchell zone substation, a reduction of $0.6 million.

The AER's overall reduction to ActewAGL Distribution's proposed augmentation capex from $99.5 million to $61.7 million (exclusive of overheads) would appear to be comprised of the sum of the AER's reductions to ActewAGL Distribution's forecast capex for the 5 major augmentation projects that were subject to the AER's internal engineering review (being $41.3 million stated inclusive of overheads).

The discrepancy between the sum of the above reductions for the 5 augex projects that were the subject of the AER's engineering review (being $41.3 million) and the AER's reduction to total forecast augex of $37.8 million (being the difference between AAD's proposed augex of $99.5 million and the AER's allowed augex of $61.7 million) would appear to be explicable by the fact that the former figures are inclusive of overheads while the latter figures are exclusive of overheads.[556]

4.4.4 ActewAGL Distribution's response

ActewAGL Distribution rejects the AER's contention that its alternative estimate for augmentation capex would suffice to enable ActewAGL Distribution to achieve the capex objectives. ActewAGL Distribution does not believe that the significantly reduced augmentation expenditure allowance set by the AER will cover the efficient costs of meeting demand from new

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[554] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-41

[555] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-31

[556] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-30 to 6-31

suburbs in the Molonglo district, or to undertake important zone substation refurbishment works necessary to meet regulatory obligations and requirements in respect of safety and reliability. The AER's alternative estimate does not therefore reasonably reflect the capex criteria.

In removing 5 major augmentation projects from ActewAGL Distribution's augmentation program for 2014-19, the AER does not appear to have had regard to the implications for ActewAGL Distribution's ability to meet or manage expected demand for its standard control services and comply with its regulatory obligations and requirements in respect of quality, reliability and security of supply and the safety of its distribution system over the period.

Augmentation expenditure for the Molonglo, Gold Creek and Mitchell zone substations is required to meet current and expected future demand and ensure continued quality, reliability and security of supply in those regions. ActewAGL Distribution's planned condition assessment and refurbishment program for zone substation earth grids is necessary given the age of these assets and the potential risk to ActewAGL Distribution personnel and public safety. ActewAGL Distribution's response to the AER's proposal to remove all four of these augex projects from ActewAGL Distribution's capex program is provided below, and supported by detailed project justification reports attached to this revised regulatory proposal.

ActewAGL Distribution has reviewed the prudency of its plans to install a third transformer at the Belconnen zone substation in light of updated demand forecasts. Based on those updated demand forecasts and the associated probability of future block load increases in the Belconnen region, ActewAGL Distribution now considers that the most prudent option is to manage network constraints by transferring load to other zone substations (load balancing) on a permanent basis, or during periods when the Belconnen zone substation 2 hour emergency rating is exceeded. Accordingly, ActewAGL Distribution has reduced its forecast augmentation expenditure program for the 2014-19 regulatory period by $13.1 million ($2013/14). Details of the Belconnen zone substation project, and ActewAGL Distribution's revised approach are set out in the Belconnen zone substation PJR, which forms Attachment D5 to this revised proposal.

ActewAGL Distribution observes that the AER's trend analysis provides no support for its decision to reduce ActewAGL Distribution's forecast augmentation capex for the 2014-19 period. To the contrary, this AER analysis confirms that ActewAGL Distribution's proposed forecast of augmentation capex for 2014-19 is consistent with its augmentation capex incurred in the 2009-14 regulatory control period. In fact, ActewAGL Distribution's revised augex forecast of $79.8 million ($2013/14) is lower than actual capex of $94.6 million ($2013/14) in the 2009-14 regulatory period.

This leaves the AER's findings in respect of excess capacity in ActewAGL Distribution's network and the conservatism of ActewAGL Distribution's augmentation planning criteria, and the AER's internal engineering review of 5 of ActewAGL Distribution's major augmentation projects. ActewAGL Distribution addresses each of these matters, in turn, below.

Network utilisation, excess capacity and load balancing

ActewAGL Distribution rejects the AER's general finding that there is likely to be excess capacity in the ActewAGL Distribution network that could be utilised ahead of additional augmentation investment.

This finding reflects an overly simplistic interpretation of network utilisation in that it assumes that:

- there is an opportunity to meet a demand constraint at one point on the network by transferring energy from elsewhere on the network where there is excess capacity, without any reference to or consideration of the relevant meshed 11kV network connections between the zone substations; and
- the long term NPV cost associated with transferring excess capacity to elsewhere on the network is lower than the cost of undertaking new augmentation investment to meet the demand constraint.

ActewAGL Distribution has already considered all possible avenues for utilising existing capacity instead of undertaking augmentation projects, and its examination of these options is detailed in the project justification reports for each of the major augmentation projects proposed by ActewAGL Distribution that are attached to this revised regulatory proposal. With the more recent exception of the Belconnen upgrade, the utilisation of existing capacity was not found to be a feasible solution for these major augmentation projects.

In response to the draft decision, ActewAGL Distribution undertook a comparison of the AER's historical and forecast utilisation factors by zone substation analysis with its own. It would appear that the AER has most likely included Angle Crossing substation in its analysis, which has the effect of understating the utilisation of ActewAGL Distribution's network and overstating excess capacity. As pointed out in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period, Angle Crossing substation is a specialist 'temporary' zone substation that was constructed during the 2009-14 regulatory period.[557] Angle Crossing zone substation has a low utilisation factor, which has the effect of lowering ActewAGL Distribution's overall network utilisation factor even though there is very little opportunity to transfer excess capacity from Angle Crossing to elsewhere on the network. As such, it should be excluded from any analysis of network utilisation.

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[557] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p.176.

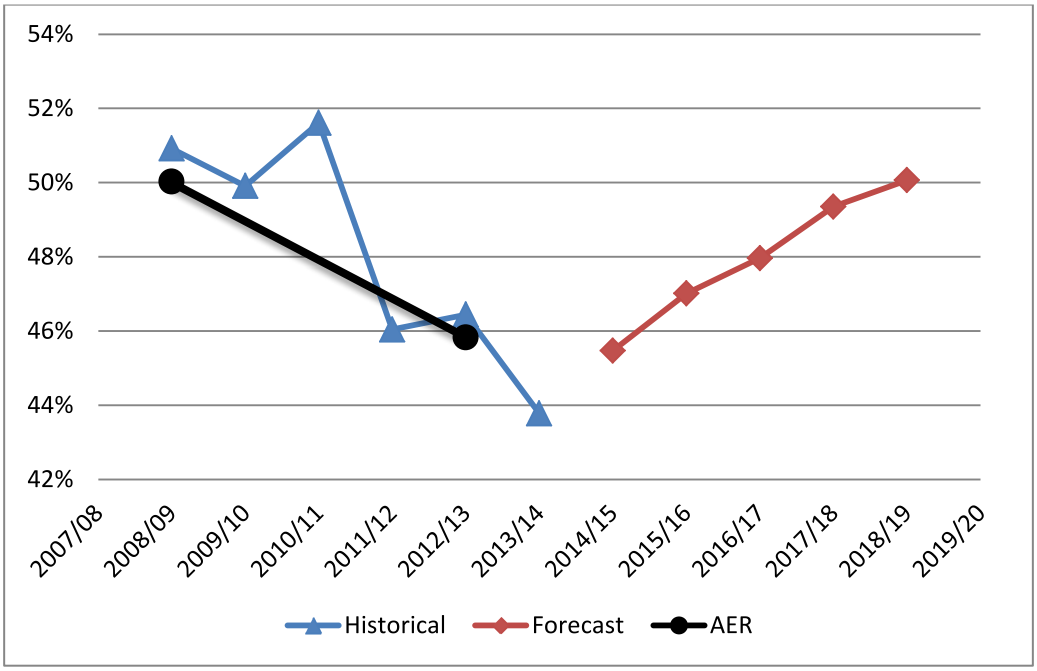
In any case, a reduction in ActewAGL Distribution’s utilisation factor from one year to the next does not necessarily indicate that a lower level of augmentation capital expenditure is required. Because of the relatively small size of the ActewAGL Distribution network, the utilisation factor is likely to change from year to year because adding significant components such as power transformers to the network, or other environmental factors will have a significant impact on network utilisation.

Figure 4.1 shows the historical and forecast average utilisation trend. This is consistent with the AER's analysis that average utilisation of zone substations fell from 50 per cent in 2008-09 to 46 per cent in 2012-13. There are three main reasons for this fall in utilisation over the period, namely:

- a very mild year in 2011/12, resulting in abnormally low system demand;
- the introduction of a new transformer at Civic in 2012; and
- the commissioning of the East Lake zone substation in December 2013.

ActewAGL Distribution does not expect this downward trend in zone substation utilisation to continue in the 2014-19 period. Rather, it is expected to increase as shown in Figure 4.1. The downward trend in zone substation utilisation following the introduction of new capacity in the network is to be expected, as is the subsequent upward trend of zone substation utilisation as the newly installed capacity starts to relieve identified capacity constraints.

Figure 4.1 – ActewAGL Distribution's historical and forecast average zone substation utilisation trend (excludes Angle Creek Crossing)



It should be noted that ActewAGL Distribution employs a best practice design principle of using relatively large standard size zone substation transformers (55 MVA) and spacing these zone substations relatively widely (average 6 km straight line distance). This design principle is suited to the widely spaced population centres within the ACT, minimising the cost of establishing zone substation infrastructure, but limiting the opportunity for load balancing between them.

For example, the extra capacity at Civic zone substation has the potential to take load from City East and Belconnen zone substations, with potential to supply the Molonglo District with 3.2 MVA in 2017 via the Black Mountain feeder. This is planned as part of the initial supply solution to the Molonglo region. However, further transfers to the Molonglo region are limited due to the distance and difficult terrain. East Lake Zone Substation has potential to transfer energy to Fyshwick and Telopea Park.

ActewAGL Distribution has reviewed the potential to use available capacity at existing zone substations as an alternative to network augmentation, in the context of the AER's draft decision on it augmentation program. These are summarised below.

- The Molonglo district initial supply, as described in the Molonglo supply solution PJR, includes three feeder augmentation projects which will provide the first 8.6 MVA of load from existing zone substations before a longer term solution is required. The current demand forecast indicates this initial 8.6MVA will supply the Molonglo District until 2018/19 at which time the forecast demand growth exceeds 8.6MVA. Woden zone substation will provide 5.4MVA by the extension of 2 existing feeders and Civic zone substation will provide 3.2MVA by the extension of 1 existing feeder.

- The Molonglo district long term supply solution from 2018/19 includes an assessment of 3 options, one of which is an 11kV feeder only option, supplying electricity from the available capacity at 3 existing zones substations (Woden, Civic, and Latham). This option has been assessed as being a higher net cost solution to the recommended Molonglo zone substation.
- Belconnen Zone Substation – as stated above, updated demand forecasts indicate that a third transformer at the Belconnen zone substation is not likely to be required during the 2014-19 regulatory period. This will be reassessed on an annual basis as part of the annual demand forecast. Further to this, ActewAGL Distribution's options analysis has assessed that when a network constraint is identified at Belconnen zone substation in the future there is potential for transfer of load from Belconnen zone substation to adjacent zone substations allowing the deferment of the third transformer at the otherwise fully utilized Belconnen zone substation. These load transfers are identified in Table 4.4 below.

Table 4.4 Potential Load Transfers from Belconnen Zone Substation

Feeder	Transfer to Zone Substation	Load Transfer - MVA
Swinden	City East	2.30
Benjamin Hayden Swinden	Civic	3.60
Maribyrnong Meacham Swinden William Slim	Gold Creek	3.60
Bean Cameron STH Chan Emu Bank Laurie McGuinness Meacham	Latham	2.30
Total		**11.80**

ActewAGL Distribution therefore rejects the AER's assertion that 'there is excess capacity in the network that could be utilised ahead of additional augmentation investment'. The statement is misleading and shows a lack of understanding by the AER about the potential for planned projects to utilise capacity, recent and forecast network utilisation trends, and the potential for ActewAGL Distribution to transfer load on its network.

Following a review of updated demand forecasts and the probability of future block loads, it remains the case that planned augmentation in Molonglo, Mitchell and at Gold Creek is necessary to meet current and future demand and ensure continued reliability in those regions.

ActewAGL Distribution's augmentation planning criteria

ActewAGL Distribution strongly rejects the AER’s view that its augmentation planning criteria are overly conservative. As discussed in section 4.3.4 above, in planning the augmentation of its electricity distribution and transmission networks, ActewAGL Distribution uses a mixture of deterministic (rule based) criteria and probabilistic criteria as outlined in section 6.5 of ActewAGL Distribution’s regulatory proposal for the subsequent regulatory period. Both ActewAGL Distribution’s deterministic and its probabilistic planning criteria incorporate risk parameters.

Further, ActewAGL Distribution rejects the AER’s finding that ActewAGL Distribution’s distribution network augmentation standard does *“… not incorporate the change in the ACT Electricity Distribution Supply Standards Code (2013)…”*[558] The change in the *ACT Electricity Distribution Supply Standards Code (2013)* removed the following clause:

> *8.1 Contract to Ensure Supply Capacity*
>
> *An Electricity Distributor must include provisions in its Standard Customer Contract to the effect that the Electricity Distributor will take all reasonable steps to ensure that its Electricity Network will have sufficient capacity to make an agreed level of supply available at the Point of Supply, providing that the Customer has complied with the requirements of the Service and Installation Rules and has paid any applicable fees.*

The change in the *ACT Electricity Distribution Supply Standards Code (2013)* removed the need to ‘document’ the supply capacity requirement in its standard customer contract. This does not mean that ActewAGL Distribution is no longer obliged to ensure sufficient electricity supply capacity is available to its customers, and the AER’s interpretation of it as such is startling.

Ensuring sufficient capacity is available to provide a reliable, safe and secure supply to customers is a core requirement of the National Electricity Law. ActewAGL Distribution has carefully

[558] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-34

considered the changes to the *ACT Electricity Distribution Supply Standards Code (2013)* and has found this to have no impact on ActewAGL Distribution's network planning criteria.

Unserved energy (energy at risk) modelling

In undertaking its engineering review of ActewAGL Distribution's proposed major augmentation projects, the AER noted that ActewAGL Distribution did not present any analysis on the probability of the risk and associated cost of unserved energy.

The risk of customer outages and unserved energy is inherently being taken into account in ActewAGL Distribution's network planning criteria, without the performance of discrete unserved energy calculations using VCR, as discussed in section 4.3.4 above.

ActewAGL Distribution previously applied unserved energy modelling to justify the replacement of the 11 kV switchboards at the Civic zone substation during the 2009-14 regulatory period. However, the relatively small size of the ACT distribution system and the infrequency with which major substations or feeders become overloaded do not present many opportunities to apply unserved energy modelling. Furthermore, this type of modelling is not suitable for all augmentation projects, and in some cases involves a number of subjective assumptions that can lead to potential inaccuracies in the output results of the modelling. These assumptions include:

- the assessed value of customer reliability (VCR);
- the use of average asset fault rates (whether they are DSNP specific or an industry average);
- the lack of 'age/condition sensitivity' in the results of such modelling (the modelling produces the same level of 'unserved energy' for a 'new' substation, as it would for an aging substation at the end of its service life, when average outage rates are applied); and
- the lack of 'time sensitivity' in the results, such that all unserved energy is valued at the same amount even though it is widely accepted that customer acceptance of outages decline as the duration of the outage increases.

ActewAGL Distribution is aware of the range of deterministic, probabilistic and hybrid (a mixture of both), system security and planning criteria used by most DNSPs in Australia. In 2009 this was the subject of an AEMC investigation and report into the various jurisdictional requirements on, and planning processes undertaken by electricity DNSPs operating in the NEM. [559] The report prepared by SKM (now Jacobs) represents a detailed analysis of the similarities and differences of a wide range of standards, processes, and activities that are followed by jurisdictional

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[559] SKM 2009, *Advice on Development of a National Framework for Electricity Distribution Network Planning and Expansion,* 13 May 2009. This report was prepared by SKM for the AEMC and led to the 2011 amendments to the NER to provide for a national framework for electricity distribution network planning and expansion.

regulators and DNSPs in analysing and planning for augmentation and expansion of their distribution networks. There have been further changes and refinements by some DNSPs (including ActewAGL Distribution) to their security and planning criteria since that time.

ActewAGL Distribution understands that it is not the only DNSP in the NEM that does not use unserved energy modelling to justify the scope and timing of augmentation projects. Indeed, the majority of DNSPs still use a mixture of mainly deterministic criteria, together with an acceptance of the risk of loss of load under certain contingency conditions, but with the magnitude and duration of lost load constrained to certain values.

ActewAGL Distribution is aware that the unserved energy approach has been used by DNSPs in Victoria to optimise the scope and timing of zone substation augmentation projects for many years. However, there are important differences between the ways in which substation ratings are determined by the Victorian DNSPs to apply their unserved energy calculations, when compared with the ActewAGL Distribution's substation ratings. These differences can be summarised as follows:

Victorian DNSPs:	Timing of zone substation augmentation is when load exceeds cyclic emergency rating and unserved energy equals annualised cost of augmentation.
ActewAGL Distribution:	Timing of zone substation augmentation is when load exceeds two hour emergency rating of the substation.

After reviewing the network planning criteria of other DNSPs, Jacobs concluded the following:

The use of the higher (two hour) emergency rating by ActewAGL Distribution essentially means that it is operating within the same "risk zone" as the unserved energy approach used by the Victorian DNSPs. That is, ActewAGL Distribution is not 'overly conservative' compared to Victorian DNSPs when it comes to optimising the timing of zone substation augmentation.[560]

In response to the AER's draft decision to reject the Molonglo zone substation augmentation proposal – a project that ActewAGL Distribution considers critical to the long term interests of consumers in the Molonglo region – ActewAGL Distribution undertook an analysis of the three viable options over a 30 year period. The inclusion of the VCR calculation and 11kV feeder losses did not alter the outcome of the NPV analysis and in fact strengthened the economic evaluation of the preferred option.

[560] See attachment D4, Jacobs, 2015, Review of AER Draft Decision – Augex, January 2015, p.10

In future, ActewAGL Distribution will consider applying energy-at-risk modelling to suitable projects to optimise the timing of capex. In most cases, the time it takes to transfer load to neighbouring substations has been calculated in relation to ensuring reliability on the core grid and customer supply. There hasn't been, and there is unlikely to be in the future, the same opportunity for ActewAGL Distribution to use unserved modelling on a scale comparable to Victorian DNSPs.

Further, the AER incorrectly states that ActewAGL Distribution's proposed VCR values for STPIS purposes may have been used to justify the timing of some major augmentation projects (particularly Molonglo and Belconnen). This is not the case, as the justification and timing of the projects have been based on the ActewAGL Distribution *Network Augmentation Standard*, and the Distribution Network Planning and Expansion Framework, not on the basis of project specific unserved energy (also known as energy at risk) and VCR studies. However, VCR calculations have been used to assess the best long term consumer supply solution.

AER's internal engineering review

ActewAGL Distribution's response to the AER's internal engineering review in respect of each of the five major augmentation projects reviewed is set out below.

At the outset, however, ActewAGL Distribution observes that the draft decision, which the AER has informed ActewAGL Distribution reflects all calculations and analysis performed in its engineering review, includes only:

- a superficial description of the methodology adopted by the AER in its internal review and its terms of reference that runs to a little over a page;[561] and
- a discussion of the analysis performed, and findings reached, in the AER's review of 5 major augmentation projects proposed by ActewAGL Distribution at an estimated cost of $41.3 million ($2013/14), the majority of which is disallowed on the basis of that review, that is a mere 5 pages in length.[562]

Further, in performing its review, the AER did not conduct a site visit to discuss technical aspects of ActewAGL Distribution's major augmentation projects with it, cancelling plans made for such a site visit on more than one occasion. By contrast, the NSW DNSPs had the opportunity to discuss technical aspects of their key augmentation projects with the AER's engineering consultant

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[561] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix B*, pp. 6-80 to 6-81

[562] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-36 to 6-41

(Worley Parsons) during site visits. The AER's cancellation of plans for, and ultimate failure to conduct, a site visit in respect of ActewAGL Distribution's augmentation program is surprising when viewed against the background that the AER, in essence, concludes as a consequence of its engineering review that it had received insufficient evidence in respect of project evaluation, justification and timing for each of the projects reviewed.

Molonglo zone substation

ActewAGL Distribution has prepared a detailed project justification report for the Molonglo zone substation project which addresses the AER's concerns with the adequacy of ActewAGL Distribution's risk and options analysis and justification of project timing. This can be found at Attachment D6 to this revised regulatory proposal.

The key business and regulatory compliance drivers for augex in respect of the Molonglo zone substation are:

- compliance with the Rules and regulatory obligations;
- maintenance of security of supply and system reliability;
- promotion of efficient investment for the longer term benefit of consumers;
- efficient asset management; and
- management of risk (financial, operational, health and safety, environmental and legal).

The Molonglo supply solution PJR provides a detailed assessment of the following four options:

1. Do Nothing
2. Molonglo zone substation
3. Feeder Augmentations from existing zone substations
4. Woden zone substation Extension

The AER states that ActewAGL Distribution did not include any assessment of the 'do nothing option and non-network solutions.[563] The 'do nothing' option was assessed by ActewAGL Distribution but was not considered a technically feasible solution because it places ActewAGL Distribution in breach of fulfilling its regulatory obligations with respect to system reliability and security of supply.

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[563] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix B*, p.6-37

As for non-network solutions, Demand Side Management (DSM) options were also considered for both the initial supply and deferral of the long term supply solution for the Molonglo district. ActewAGL Distribution found that there is no value in adding additional DSM costs to ‘free up’ capacity at adjacent substations, such as the Woden zone substation as available capacity already exists. Further to this ActewAGL Distribution investigated the use of a DSM solution to offset the initial network supply solutions (the initial 8.6MVA supplied by Woden and Civic zone substations). The cost of providing a DSM solution was based on Diesel Rotary Uninterruptable Power Supply (DRUP) and is significantly higher ($21.7 million) compared to the network supply option considered ($1.6 million). This is shown in Table 4.5.

Table 4.5 Comparison of DSM and Network Solutions for initial Molonglo District Supply

	2015	2016	2017	2018	2019	Total
Demand Forecast - MVA	2.1	3.8	5.6	7.2	8.7	
Network Initial Supply Option (capex)						
Hilder feeder extension	$400,000					$400,000
Streeton feeder extension	$350,000					$350,000
Black Mountain upgrade			$850,000			$850,000
Total	**$750,000**	**$0**	**$850,000**	**$0**	**$0**	**$1,600,000**
DSM Initial Supply Option (opex)						
DRUPS	$1,903,020	$2,854,530	$4,570,670	$5,709,060	$6,660,570	**$21,697,850**

However, in recognition of the likelihood of DSM being an integral part of the Molonglo District demand requirements, a lower 2.5kVA per household value has been used for developing the long term demand forecast for the Molonglo District. This figure could nominally be in the range of 2.5kVA to 3.0kVA.

The AER contends that ActewAGL Distribution appears not to have ‘sufficiently investigated distribution feeder augmentation solutions from the Woden zone substation. In particular, the AER states:

“ActewAGL can also raise the capacity of Woden zone substation by about 20 MVA for a comparatively smaller cost. This would require a transformer tail cable upgrade, similar to what ActewAGL carried out at the Belconnen zone substation. This alternative would potentially provide a more efficient solution.”

ActewAGL Distribution considered the potential to increase the capacity at Woden zone substation by upgrading transformer tails and did not find this to be a cost effective long term solution. Upgrading transformer tails at the Woden Zone Substation would result in a ‘summer firm/2hr emergency’ rating increase of 5 MVA/0 MVA and a ‘winter firm/2hr emergency’ rating increase of 15 MVA / 7 MVA. A more cost effective way of providing this additional MVA would be to supply 5.5 MVA from Woden zone substation and 5.5 MVA from Civic zone substation, however this was assessed and found to be an unsuitable long term solution to supplying 55,000 consumers in the Molonglo District.

Woden zone substation is presently servicing the Molonglo district and will continue to do so by extending two nearby 11kV feeders with available capacity. A third nearby feeder from Civic zone substation will also be extended to provide for the initial Molonglo district supply. This feeder augmentation work is planned for the period 2015 to 2017. However, the demand growth in the Molonglo district is forecast to exceed the augmented feeder capacity by 2018/19.

The new zone substation at Molonglo once constructed, will also enable load balancing through the transfer of a portion of load from Weston Creek currently supplied from the Woden zone substation, thereby deferring the need for capacity augmentation at the Woden zone substation for approximately 10 years.

An updated 30 year NPV analysis has been completed on the three viable options. Construction of the Molonglo zone substation remains ActewAGL Distribution's preferred solution. It is also the lowest cost 30 year NPV solution to service the forecast demand requirements of the Molonglo District to 2043 (at $21.8 million ($2014/15)).

The Molonglo supply solution project includes the continuation of the initial 8.6MVA feeder supply solution from existing zone substations and building the long term secure and reliable supply solution of Molonglo zone substation and associated feeders to be commissioned by 2018/19. This represents a deferral in the timing by 12 months compared to that proposed in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period.

The revised timing of Molonglo zone substation is driven by the new 'occupied' dwelling electricity demand requirements and demonstrates that ActewAGL Distribution does not take an 'overly conservative' approach to network augmentation. In deferring the timing of the project by twelve months, ActewAGL Distribution has assessed that the 11kV feeders providing the initial supply solution will be above their firm rating but lower than their emergency rating in the year prior to the zone substation being required.

ActewAGL Distribution is committed to this augmentation project and strongly believes that it promotes economic efficiency with respect to direct control network services as required by the National Electricity Rules Chapter 6.5.7 and provides a solution in the long term interests of consumers as required by the National Electricity Law. This project is also subject to the Regulatory Investment Test – Distribution (RIT-D).

The ACT Government Land Development Agency recently wrote to ActewAGL Distribution expressing its concern with the AER's draft decision to disallow capex for the Molonglo zone substation in the 2014-19 period, and asking ActewAGL Distribution to advise on the implications of this draft decision on the future development of the Molonglo region.[564] This letter forms Attachment D7 to this revised proposal.

ActewAGL Distribution notes the concerns raised by the AER with respect to risk allowances and internal management costs included in ActewAGL Distribution's cost estimate for the Molonglo zone substation. In particular the AER stated:

> '*In addition we note ActewAGL's costing for the project included $3.99 million for risk allowances to manage the uncertainty associated with the accuracy of the project estimate. It also included internal management costs of $2.63 million. We consider risk allowances are not a part of augex and NSPs should not pass such items on to the customer since ActewAGL expenditure may be either higher or lower than the estimates. We did not assess the efficiency of the internal management cost. However, our view is the total internal management cost of $2.63 million is at the very high end of the normal range for project management.'*[565]

ActewAGL Distribution has included a risk allowance of between 10 per cent and 20 per cent for the Molonglo zone substation augmentation project. This is consistent with the 'scope factor allowance' range recently proposed by Jemena Gas Networks (JGN)'s in respect of its 2015-20 capex forecasts.[566] Similar to ActewAGL Distribution's 'risk allowance,' JGN applies a 'scope factor allowance' to forecast labour and materials costs for projects that cannot be fully scoped at the strategic estimate stage as the scope arising from more detailed design, consultation and site investigation has not been fully defined.[567]

In respect of 'internal management costs', ActewAGL Distribution's cost estimate for the Molonglo zone substation project include a 10 per cent - 15 per cent allowance for internal costs which it considers to be efficient and within the accepted industry range for such costs. Internal management costs include:

- Project management, commissioning management
- Training & inductions

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[564] See Attachment D7, Letter from Mr David Dawes, Director-General Land Development Agency to Mr Michael Costello, CEO ActewAGL Distribution dated 17 December 2014

[565] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6:* p. 6-38

[566] See Attachment D8, Jemena Gas Networks (NSW) Ltd, 2014 *Appendix 06 09 Project estimation methodology review,* 4 June 2014, pp.5-6

[567] Jemena Gas Networks (NSW) Ltd, 2014 *Appendix 06 09 Project estimation methodology review,* 4 June 2014, p.4

- Safety compliance audits
- Design and standards reviews and approvals
- Safety, environmental, constructability, operability, quality reviews
- Legal / commercial reviews
- Permits
- Approvals management

Further details of internal costs included in ActewAGL Distribution's cost build up for the Molonglo zone substation are included in the detailed PJR attached to this revised proposal.

Molonglo pass through event

In the event that the AER does not accept augex for the Molonglo zone substation in its final decision, ActewAGL Distribution proposes a Molonglo pass through event be specified in the distribution determination as an additional pass through event to apply for the subsequent regulatory period in accordance with clause 6.5.10 of the Rules.

In so doing, ActewAGL Distribution refers to and repeats its contentions regarding the relevant legal and regulatory framework for nominated pass through events set out in section 11.2 of this revised regulatory proposal.

As the AER must be satisfied that its own total capex estimate reflects the capex criteria in accordance with clause 6.12.1(3)(ii) of the Rules, it will be implicit in any decision by the AER to disallow augex in respect of the Molonglo zone substation that this expenditure was not needed given the AER's expectation of the demand forecasts and cost inputs for the purposes of the capex criteria - that is, it will be implicit in such a decision that the AER does not expect the demand conditions which would necessitate the construction of the Molonglo zone substation to eventuate.

As the AER notes, the pass through provisions provide a means for a service provider to pass on unexpected capex to customers where appropriate.[568] This is consistent with MCE Standing Committee of Officials consideration in developing Chapter 6 of the Rules that uncertainty around certain capex projects could be dealt with via the pass through provisions. [569]

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[568] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6:* p. 6-17

[569] AEMC 2012, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, Rule Determination, November, p.183

The Molonglo pass through event provides a mechanism for ActewAGL Distribution to recover efficient costs in constructing the zone substation where demand conditions eventuate, contrary to the AER's expectation at the time of making the distribution determination, which necessitate this additional expenditure.

A Molonglo pass through event would also be consistent with the nominated pass through considerations for the reasons outlined in Table 4.6.

ActewAGL Distribution's proposed definition of the Molonglo pass through event is set out below. Pursuant to this definition, the Molonglo pass through event would occur when a level of demand eventuates that necessitates that an augmentation project be initiated. The attached Molonglo project justification report indicates that a zone substation will take 3 years to complete. To have the zone substation in place before the emergency rating of the feeders is exceeded; therefore, the project would need to be initiated when maximum demand exceeds 3.8 MVA. ActewAGL Distribution has therefore defined the pass through event to occur when demand reaches 3.8 MVA.

ActewAGL Distribution proposes a Molonglo pass through event defined as follows be specified in the distribution determination as an additional pass through event for the subsequent regulatory period:

A Molonglo pass through event occurs if:

(1) demand from the Molonglo district exceeds 3.8 MVA and is growing at a rate greater than 1.5MVA per annum;

(2) as a result, ActewAGL Distribution incurs or is likely to incur higher or lower costs in augmenting its network to provide direct control services than it would have incurred otherwise; and

(3) the event is not covered by any category of pass through event specified in clause 6.6.1(a1)(1) to (4) of the NER.

Table 4.6 Molonglo pass through event and the nominated pass through event considerations

Nominated pass through event consideration	Molonglo pass through event
whether the event proposed is an event covered by a category of pass through event specified in clause 6.6.1(a1)(1) to (4) (in the case of a distribution determination)	The Molonglo pass through event is, by definition, not covered by any event specified in clause 6.6.1(a1)(1) to (4) by reason of paragraph (3) of the proposed definition of that event.
whether the nature or type of event can be clearly identified at the time the	The Molonglo pass through event is clearly identified as it is defined by the occurrence of a specified level of demand in

Nominated pass through event consideration	Molonglo pass through event
determination is made for the service provider	a defined district which requires ActewAGL Distribution to incur costs in augmenting its network.
whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event	ActewAGL Distribution cannot prevent the occurrence of the event as it does not have any ability to control whether the specified demand eventuates. ActewAGL Distribution cannot reasonably prevent or substantially mitigate the cost impact of such an event as it is a legal and regulatory obligation under the NEL, NER and Utility Act (ACT) for ActewAGL Distribution to maintain security of supply and system reliability. Any ability for ActewAGL Distribution to control the cost impact of the event would be at the margin because, where the specified demand eventuates resulting in the occurrence of the event, the Molonglo zone substation will be required to maintain security of supply and system reliability in accordance with these legal and regulatory obligations.
whether the relevant service provider could insure against the event, having regard to: • the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or •)whether the event can be self-insured on the basis that: – it is possible to calculate the self-insurance premium; and – the potential cost to the relevant service provider	Insurance for the event is not available on reasonable commercial terms and the event cannot be self-insured. First, ActewAGL Distribution considers it unlikely that any insurance company would provide insurance based on demand conditions in a localised portion of ActewAGL Distribution's electricity network. Secondly, ActewAGL Distribution is unable to self-insure for the event. The cost to ActewAGL Distribution ($21.8 million) represents a large portion of revenue and would significantly impact on ActewAGL Distribution's ability to provide network services. To put the cost (which could not be rolled into the RAB) into perspective it would be appropriately 10 per cent of ActewAGL Distribution's combined distribution and transmission average annual revenue requirement - approximately an order of magnitude higher than the materially threshold specified in the Rules for cost pass through events.

Nominated pass through event consideration	Molonglo pass through event
would not have a significant impact on the service provider's ability to provide network services	
any other matter the AER considers relevant and which the AER has notified Network Service Providers is a nominated pass through event consideration	The AER purports to notify ActewAGL Distribution in its draft decision that consistency in its approach to assessing nominated pass through events across its determinations where possible is another matter the AER considers relevant and is a nominated pass through event consideration.[570] In response, ActewAGL Distribution contends as follows: • As discussed in section 11.5.4 of this revised regulatory proposal, ActewAGL Distribution queries whether this is properly considered by the AER to be a nominated pass through event consideration in accordance with paragraph (e) of those considerations. The AER has not notified NSPs generally that this is to be a nominated pass through event consideration, as is required by paragraph (e) if a matter the AER considers relevant is to constitute a nominated pass through event consideration. In any event, consistency in the AER's approach to assessing nominated pass through events should be a product of the AER's application of the NEO, RPPs and the nominated pass through event considerations specified in paragraphs (a) to (d). It is not a matter that is, of itself, relevant to the assessment of whether the acceptance of a nominated pass through event would promote the relevant statutory objects and

[570] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 15*: p. 15-10

Nominated pass through event consideration	Molonglo pass through event
	thus permissibly notified to NSPs and considered by the AER pursuant to paragraph (e) of the considerations. • Even if consistency in its approach to assessing nominated pass through events across its determinations where possible is properly considered to be a nominated pass through event consideration, ActewAGL Distribution is not aware of any determinations by the AER with which it would be inconsistent to accept the Molonglo pass through event as a nominated pass through event.

Belconnen zone substation

As stated above, updated demand forecasts indicate that a third transformer at the Belconnen zone substation is not likely to be required during the 2014-19 period. Consequently, capex for this project has been removed from the 2014-19 capex program.

Zone substation earth grids upgrade

Each ActewAGL Distribution zone station and switching station has an earth grid installed, the purpose of which is to maintain the safety of personnel and public at and near the site through:

- prevention of hazardous touch, step and transfer potentials during fault conditions;
- ensuring all accessible, non-current carrying structures and equipment are maintained at the same potential;
- preventing the build-up of static charges on equipment;
- ensuring a continuous, low impedance path to earth for lightning surges, switching surges and 50 Hertz fault currents; and
- providing a consistent reference for the network voltage levels for the correct operation of the network protective devices.

The earth grids at the respective stations were installed when the stations were first commissioned. Over 80 percent of earth grids in ActewAGL Distribution's network have been in operation for over 25 years, with the oldest installation approaching 55 years of age. The earth grids have been in-service for a long time raising a concern about their *integrity* to be effective given that substation loads have increased with consequent increase in network fault levels.

As the earth grids are buried beneath the station surfaces and some equipment foundations, there is no easy way to inspect their existing condition. Modern testing includes frequency injection testing which replicates fault conditions and provides information on the impedance, health and fault paths of the earth grid. ActewAGL Distribution proposes to undertake condition assessment testing, and where required necessary remedial works to minimise project costs and mitigate risks associated with the deterioration of earth grids. This will ensure that ActewAGL Distribution fulfils its duty of care under relevant WHS legislation.

The 'do nothing' option, which the AER has endorsed in its draft decision, has not been seriously considered by ActewAGL Distribution as most of the assets have been in service beyond their 'economic' asset life. ActewAGL Distribution considers that a 'run to failure' asset management strategy in this case would result in an unacceptably high level of risk to the safety of ActewAGL Distribution personnel and the public, including the risk of network protection malfunction and collateral damage to other major network assets.

In a worst case scenario, the failure of an earth grid at a zone substation to perform its designed function could lead to equipment malfunction and explosion or electrical shock risks potentially resulting in injury or death to ActewAGL Distribution personnel and the public. Alternate upstream distribution system protection arrangements are designed to activate if zone substation protection systems fail to protect personnel, people or equipment, which would result in loss of electricity to large numbers of customers in multiple districts and extended outages which could continue for days.

Condition assessment based refurbishment is the most prudent and cost effective solution for ensuring compliance to safety requirements and minimises ActewAGL Distribution's residual risk of incidents occurring due to deteriorated earth grids.

ActewAGL Distribution notes the AER's concern regarding a lack of 'clear scope' or 'certainty of the need for expenditure.' However, in such a case as this it is very difficult to have a clear scope or certainty regarding required expenditure until the earth grid is inspected and tested. Since the release of the AER's draft decision, ActewAGL Distribution has commenced condition testing of earth grids at two zone substations. Based on this assessment, ActewAGL Distribution has revised its program of earth grid condition assessment and refurbishment using a probabilistic methodology. This suggests that approximately one third of ActewAGL Distribution's earth grids will require refurbishment. ActewAGL Distribution proposes revised capex for this program of $1.2 million ($2013/14) to undertake a major earth grid upgrade at one zone substation and earth grid refurbishment work at three others during the 2014-19 regulatory period.

Gold Creek 11kV Switchboard (Feeder Bay) extension

ActewAGL Distribution maintains that this project is required to enable it to achieve the capex objectives, specifically to meet its regulatory obligations and requirements with respect to reliability and security of supply. Without the proposed extension of the 11kV feeder bays, ActewAGL Distribution will not be able to do so.

Since the release of the AER's draft decision, ActewAGL Distribution has prepared a detailed project justification report which addresses the AER's concerns with ActewAGL Distribution's investigation of alternative solutions. This report considers three options for addressing the lack of spare feeder bays at the Gold Creek Zone Substation. It can be found at Attachment D10 to the revised regulatory proposal. In summary, the analysis reinforces the option included in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period which recommends the extension of the 11kV switchboard at Gold Creek Zone Substation to provide for the forecast demand in Gungahlin and Mitchell, including consolidation (paralleling) of feeders. This represents the most technically feasible option and provides a minimal incremental cost approach to addressing forecast growth in the next regulatory period.

There are currently no spare feeder bays at the Gold Creek zone substation. All twenty (ten on each 11kV switchboard) are utilised to feed existing loads. Gungahlin and Mitchell have been experiencing higher than average demand growth at around 3.3 percent per annum over the past 10 years and this steady growth is forecast to continue over the next 10 years. Gold Creek zone substation is the primary source of electricity supply for Gungahlin and Mitchell.

Connection applications have been received for two major commercial block loads planned to be commissioned by 2015/16 and 2016/17 respectively. The nature of both these loads [c-i-c [redacted]] requires a secure and high level of reliability. The proponents have met with ActewAGL Distribution to discuss and ensure a commitment from ActewAGL Distribution to provide a high level security of supply. Two new feeders are planned with a potential third feeder required for security of supply to one of these commercial block loads.

A third block load planned for supply from the Gold Creek zone substation is associated with the ACT Government's planned Light Rail project. This project is planned toward the end of the 2014-19 regulatory period. The ACT Government has communicated to ActewAGL Distribution the need to ensure and strengthen HV infrastructure and connections such that they will provide the high level of electricity supply security and availability required for a highly visible and relied upon consumer based project.

A minimum of seven additional feeder bays are forecast to be required to connect forecast connections and associated load growth over the next ten years. This comprises three feeders identified for known block loads, including a feeder for additional security required for one of the commercial [c-i-c [redacted]] blocks loads. There are two feeders required to meet the forecast residential and commercial load growth from 2015 - 2020 and a further two feeders required for the forecast demand growth between 2020 - 2025

The recommended solution is the extension of the 11kV switchboards, including the optimised consolidation (paralleling) of feeders to be undertaken in two stages. This will result in the creation of seven feeder bays, and achieves the objective of providing sufficient capability to meet current and future feeder requirements of the network in a prudent and cost efficient manner. The efficiency of the preferred solution is achieved by combining a low cost feeder consolidation (paralleling) solution with the relatively more expensive but inevitable solution of expanding the existing switchboard. The project would be undertaken in two stages as follows:

- Stage 1: Feeder Consolidation; estimated at $14,000
- Stage 2: Switchboard extension; estimated at $756,000

The capex forecast for the preferred solution is estimated at $770,000 and is expected to be completed over a two year period with an expenditure forecast of $270,000 in 2015/16 and $500,000 in 2016/17.

The AER has raised the following two concerns in respect of ActewAGL Distribution's proposed Gold Creek 11kV switchboard augmentation project:

"… we understand it is a common industry solution to double up the cable termination box on the existing switchboard when facing a shortage of switch bays. This provides an additional connection terminal for new feeders at comparatively low cost. ActewAGL did not explain why it did not investigate such alternative lower cost solutions"[571] *and*

"ActewAGL's data manual shows that Gold Creek Substation has 20 feeders with firm operational ratings around 5.5 MVA each. The current substation maximum demand of about 50MVA suggests the existing feeders have substantial spare capacity for current and future load. However, ActewAGL offered no information why it did not investigate distribution feeder reconfiguration and load transfers. These solutions could free up some existing feeders or feeder bays for potential new load in the coming years." [572]

In response to the AER's concerns, ActewAGL Distribution notes the following:

- ActewAGL Distribution's proposed solution does include the doubling up (or paralleling) of cable terminations as the first stage of a two stage long term solution. Details of this solution are contained in the Gold Creek Switchboard (Feeder bay) extension PJR attached to the revised proposal; and

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[571] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6:* p. 6-40

[572] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6:* p. 6-41

- ActewAGL Distribution did investigate distribution feeder reconfiguration and load transfers in determining a recommended solution for the Gold Creek zone substation. The reconfiguration of feeders and load transfers are an integral part of the feeder paralleling solution, and details of this approach are also contained in the PJR attached to the revised proposal.

Mitchell zone substation

In response to the AER's concerns regarding the lack of information on the purpose and scope of augex proposed for the future Mitchell zone substation, ActewAGL Distribution has prepared a detailed project justification report. This report can be found at Attachment D12 to the revised regulatory proposal, and is summarised below.

The ACT Government is committed to new urban development at Kenny. The commercial load centre at Mitchell is also experiencing strong load growth. The present feeder network from the City East zone substation will not be able to supply this large load in future. This project is therefore necessary for ActewAGL Distribution to meet the capex objectives under the Rules.

ActewAGL Distribution will be required to provide an electricity supply to this new and developing urban area. ActewAGL Distribution's long term planning and most recent demand forecasts have identified the need for a new zone substation located in the Mitchell District, and that this will most likely be required in the 2019 – 24 regulatory control period. Therefore, it is planned to make a strategic acquisition of land to secure a suitable site for the future Mitchell zone substation in the 2014-19 period. The acquisition of land at Mitchell in the 2014-19 period mitigates risks associated with increased land values, land availability and the establishment of easements for new feeders.

The proposed capex for the future Mitchell zone substation is, therefore, necessary to achieve the capex objectives.

The two options considered in the project justification report are as follows:

- Option 1: Do nothing
- Option 2: Purchase land for construction of new Mitchell zone substation

The risk of ActewAGL Distribution not being able to meet the long term supply requirements of the Mitchell district and hence the capex objectives, increases over time under the 'do nothing' option. This is because the cost of purchasing land suitable for development as a zone substation site, and the associated feeder easement access requirements will be higher or the land may no longer be available for purchase. This precludes the 'do nothing' option from being considered a viable alternative.

Option 2 (purchase land for construction of a new Mitchell zone substation) is also considered cost efficient and prudent, because it enables ActewAGL Distribution to optimise its use of City East, Belconnen and Gold Creek zone substation assets. Existing capacity at City East, Belconnen and Gold Creek will continue to be considered as the first source of supply to the Mitchell district during the 2014-19 regulatory period. However, a long term (20 Year) forecast has indicated that these 3 existing substations will be approaching their capacity limit by 2022 at which time ActewAGL Distribution plans to construct the Mitchell zone substation.

The estimated cost for the acquisition of the land for the future Mitchell zone substation has been based on a third party valuation and includes estimated allowances for other associated costs.[573]

4.4.5 ActewAGL Distribution's augex program 2014-19

ActewAGL Distribution rejects the AER's alternative estimate for augex of $61.7 million ($2013/14) excluding overheads.

ActewAGL Distribution proposes a revised total augex program for the 2014-19 regulatory period of $79.8 million ($2013/14) as shown in Table 4.7 below. ActewAGL Distribution contends that this expenditure is justified by the additional material advanced in this section 4.4 and included in project justification reports attached to this revised proposal.

Table 4.7 ActewAGL Distribution's revised augmentation capital expenditure program 2014-19

($ million 2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Zone Substations	0.1	5.0	6.6	12.6	7.7	32.0
Transmission	0.6	0.6	7.8	4.1	0.0	13.2
Distribution System	6.8	3.9	7.4	4.8	6.7	29.6
Secondary Systems	1.0	1.1	1.0	1.0	1.0	5.0
Total Augmentation capital expenditure	**8.5**	**10.6**	**22.8**	**22.5**	**15.3**	**79.8**

4.5 Asset Renewal and Replacement capex

4.5.1 Overview

In its draft decision, the AER did not accept ActewAGL Distribution's proposed renewal and replacement capex (repex) of $135.3 million,[574] or $114.5 million excluding overheads. It instead

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[573] [c-i-c [redacted]

included replacement capex of $98.6 million excluding overheads in its alternative estimate of total capex, representing a reduction to ActewAGL Distribution's proposal of 13.6 per cent.

The AER's draft decision on repex was based on benchmarking at the expenditure category level, trend analysis, an engineering review of ActewAGL Distribution's major repex programs and predictive modelling of repex requirements. In summary, on the basis of this assessment, the AER concluded that:

- ActewAGL Distribution's forecast repex exceeds its long term average ActewAGL repex and it has not provided supporting evidence for this increase;[575]
- controlling for network scale characteristics, ActewAGL Distribution's historical repex does not compare favourably to that of other DNSPs in the NEM and appears high in benchmarking analysis at the expenditure category level;[576]
- the AER's review of ActewAGL Distribution's major repex programs identified that its proposal may overstate the prudent and efficient repex required to achieve the capex objectives for certain asset categories, and measures of 'asset health' suggest that ActewAGL Distribution has not demonstrated that the likely condition of its assets supports its proposed forecast repex;
- the AER's predictive modelling of repex, using its calibrated repex model, suggests that ActewAGL Distribution's proposed repex is likely to be materially overstated.

ActewAGL Distribution rejects the AER's alternative estimate for repex and considers that the AER has made a number of errors in coming to its conclusion that ActewAGL Distribution's repex forecast does not meet the capex objectives. In particular:

- The AER's attempt at assessing the relative efficiency of ActewAGL Distribution's historical repex against that of other service providers displays a lack of understanding of the nature of repex drivers, and does not make any adjustment for differences in these drivers between businesses. It is therefore not possible to draw meaningful conclusions from the AER's analysis.

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[574] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p.159. This is reported by the AER as $132.3 million ($2013/14) on p. 6-11 of Attachment 6 of the draft decision.

[575] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-45 to 6-47

[576] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-45 and 6-47 to 6-50

Moreover, the AER has itself wrongly interpreted its analysis, which in fact shows that ActewAGL Distribution has the *lowest* level of repex on the basis of the metrics used.

- ActewAGL Distribution contends that there are good reasons why future repex requirements may differ from the historic trend. One of these is any increase in the age profile of assets over time. A DNSP may also reprioritise its repex programs between regulatory periods based on an assessment of the consequence of failure by asset type and other external drivers.
- ActewAGL Distribution rejects the AER's finding that the 'asset health' of ActewAGL Distribution's network does not support the contention that there is a need for increased repex. The data used by the AER is incorrect and does not provide a true picture of the age profile of ActewAGL Distribution's assets. In reality, ActewAGL Distribution does have a substantial number of aged assets, and the age profile of its assets is increasing.
- ActewAGL Distribution contends that the AER's predictive repex modelling is based on incorrect data and asset ages that have been 'back-engineered' by the AER to produce a repex program that matches past repex trends. If the asset age assumptions adopted by ActewAGL Distribution are incorporated into the model, the resulting repex prediction is *above* the repex forecast made by ActewAGL Distribution.
- ActewAGL Distribution rejects the conclusions made by the AER on the basis of its engineering review of ActewAGL Distribution's underground cable replacement program and overhead conductor and pole top structures program and provides further supporting evidence for this expenditure.

On the basis of the above, ActewAGL Distribution maintains its forecast capex for asset replacement and renewal of $132.8 million, this being the amount required for ActewAGL Distribution to achieve the capex objectives.

ActewAGL Distribution engaged Jacobs to review the AER's draft decision on repex and to undertake a focused critique of the AER's calibrated repex model. Jacobs' reports are attached to this revised regulatory proposal.

4.5.2 ActewAGL Distribution's proposal

ActewAGL Distribution proposed a total of $135.3 million,[577] or $114.5 million (excluding overheads) in repex for the 2014-19 period. This forecast repex is almost 50 per cent higher than

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[577] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p.159. This is reported by the AER as $132.3 million ($2013/14) on p. 6-11 of Attachment 6 of the draft decision.

repex incurred in the 2009-14 regulatory control period.[578] This increase is attributable to several major replacement and renewal programs.[579]

The pole replacement, pole substation replacement and pole reinforcement programs continue to dominate the asset renewal and replacement capex forecast.[580] These programs were approved by the AER in 2009 and scheduled to continue beyond the 2014-19 period. Other key asset replacement programs scheduled for the 2014-19 period include underground cable replacement and a continuation of ActewAGL Distribution's overhead conductors and pole top structures which was commenced in the 2009-14 regulatory period.

The increase in forecast expenditure for these programs has been driven by a shift in ActewAGL Distribution's asset replacement strategy from one of 'run to failure' to either 'condition based monitoring' or 'age and condition based replacement.' This shift in strategy is necessary to ensure that ActewAGL Distribution continues to achieve the capex objectives, including in particular by discharging its duty of care obligations under relevant WHS legislation and meeting its regulatory obligations in respect of maintaining reliability and security of supply in the ACT.

4.5.3 AER's draft decision

The AER did not accept ActewAGL Distribution's proposed asset renewal and replacement expenditure forecast of $114.5 million ($2013/14, excluding overheads)[581] because it concluded that this forecast exceeded the repex required to achieve the capex objectives.[582] The AER instead included an amount of $98.6 million ($2013/14, excluding overheads) for repex in its alternative estimate of total capex for the 2014-19 period, which is 13.6 per cent less than ActewAGL Distribution's proposal.

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[578] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 168

[579] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 169

[580] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 169

[581] ActewAGL Distribution's proposed repex of $132.3 million ($2013/14) inclusive of overheads.

[582] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-11 and *Appendix A*, pp. 6-44 to 6-45

In arriving at its alternative estimate, the AER:[583]

- applied benchmarking at the expenditure category level and trend analysis of historical ActewAGL and expected repex;
- performed a review of ActewAGL's major repex programs; and
- applied predictive modelling of repex requirements.

In summary, the AER concludes as a consequence of this assessment that:

- ActewAGL Distribution's forecast repex exceeds its long term average ActewAGL repex and it has not provided supporting evidence for this increase;[584]
- controlling for network scale characteristics, ActewAGL Distribution's historical repex does not compare favourably to that of other DNSPs in the NEM and appears high in benchmarking analysis at the expenditure category level;[585]
- measures of 'asset health', specifically the age of ActewAGL Distribution's network and the utilisation of the network (where network capacity should be positively correlated to asset condition), suggest that ActewAGL Distribution has not demonstrated that the likely condition of its assets supports its proposed forecast repex. Further, ActewAGL Distribution's unplanned SAIFI, which measures the frequency of unplanned outages, has been kept at a steady level, below reliability targets from 2009 to 2013, which suggests that overall asset conditions have not deteriorated such as to justify increased repex;[586]
- the AER's review of ActewAGL Distribution's major repex programs identified that its proposal may overstate the prudent and efficient repex required to achieve the capex objectives for certain asset categories. In particular, ActewAGL Distribution has not justified the increase in

[583] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-44 to 6-45

[584] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-45 to 6-47

[585] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-45 and 6-47 to 6-50

[586] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-45 and 6-50 to 6-54

expenditure for its underground cable, overhead conductor and pole top structure categories relative to expenditure incurred in the 2009-14 regulatory control period;[587]

- the AER's predictive modelling of repex, using its repex model, suggests that ActewAGL Distribution's proposed repex is likely to be materially overstated, with the reasonable range for repex for those repex categories modelled likely to be between $58 million and $76 million (excluding overheads), that is 5 to 28 per cent lower than ActewAGL Distribution's proposed repex, ;[588]
- total repex of $22.5 million for those repex categories not modelled by the AER's repex model (being overhead conductors and pole top structures, SCADA, network control and protection, and other substation and equipment) is likely to be prudent and efficient, based on trend analysis and the AER's review of major repex programs, giving an overall reasonable range for total repex of between $70 million and $98 million;[589] and
- the lower end of the reasonable range should, however, be treated with caution as the environmental characteristics of ActewAGL Distribution's network, most notably backyard reticulation of the low voltage power supply, may add cost not included in the benchmarked unit cost.[590]

The AER has not published the results of its review of ActewAGL Distribution’s major repex programs. By contrast, the AER engaged an independent consultant, EMCa to undertake an engineering review of repex programs for NSW DNSPs, and EMCa’s report in respect of each NSW DNSP has been published on the AER’s website.

4.5.4 ActewAGL Distribution’s response

ActewAGL Distribution rejects the AER’s finding that ActewAGL Distribution’s proposal may overstate the prudent and efficient amount required to meet the capex objectives because:

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[587] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-45 and 6-54 to 6-57

[588] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-45 and 6-58 to 6-66

[589] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-45 and 6-66 to 6-67

[590] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-45

- The AER's alternative estimate for repex for the 2014-19 period is insufficient to achieve the capex objectives and will, thus, have a significant adverse impact on network reliability, security, quality and safety and ActewAGL Distribution's compliance with relevant regulatory obligations and requirements.
- The AER's comparative repex benchmarking is inconsistent with ActewAGL Distribution's actual repex in recent regulatory periods and does not adjust for differences in the major drivers of repex between businesses.
- It is not appropriate to base future repex requirements on historic expenditure.
- ActewAGL Distribution's proposed repex program is supported by the age of its assets.
- The AER has used the results of its repex modelling to deterministically set repex forecasts, despite previously stating the repex model would be used as a 'first pass' assessment.
- The AER's predictive (repex) modelling is based on incorrect data and produces results that are invalid and should not be relied upon by the AER to deterministically set repex forecasts.

Each of these issues is discussed in turn below.

Implications for network reliability, security and safety and compliance with regulatory obligations and requirements

ActewAGL Distribution strongly believes that the reduced repex allowance determined by the AER does not suffice to achieve the capex objectives specified in the Rules as is required by clauses 6.5.7(c) and 6.12.1(3)(ii) of the Rules.

The AER's proposal that ActewAGL Distribution continue its previous run to failure asset replacement strategy on assets, many of which are beyond their useful life, will result in increased reactive maintenance expenditure and where asset failure has the potential to impact employee or public safety, prevent ActewAGL Distribution to meet its duty of care obligations under WHS legislation.[591] Many of the assets due for replacement and refurbishment are located in public or trafficable areas (including back yards). Consequently, a run to failure strategy has the potential to cause serious injury or death to members of ActewAGL Distribution's workforce or the public.

Furthermore, the AER's alternative estimate will not suffice for ActewAGL Distribution, acting efficiently and prudently, to meet its regulatory obligations in respect of reliability, quality, safety and security of the network and electricity supply. This is discussed in detail in section 2.7 of this revised proposal.

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[591] Work Health Safety Act 2011 (ACT), Division 2.2, Clause 19

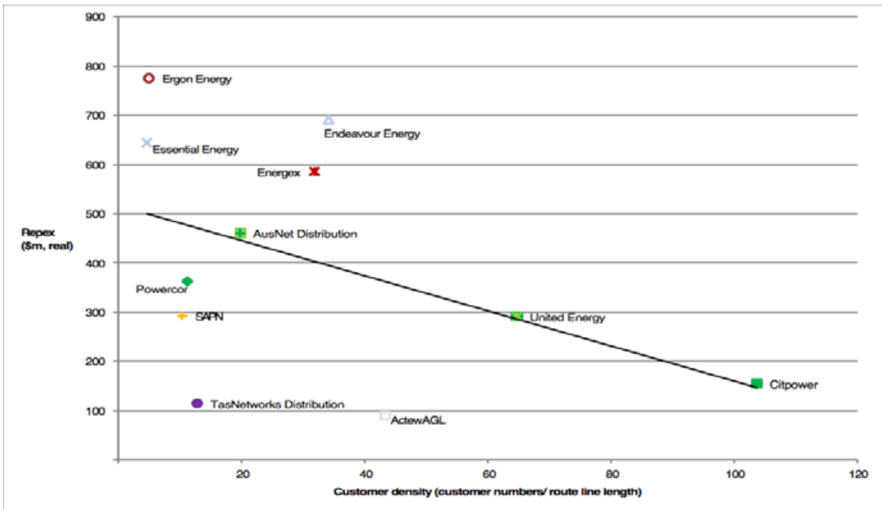
AER's repex benchmark analysis is flawed

In the draft decision, the AER attempts to assess the relative efficiency of ActewAGL's historical repex against that of other service providers by applying customer density and capacity density to normalise for the impact of network size when making comparisons of total repex.

ActewAGL Distribution asked Jacobs to review the AER's repex decision, including the AER's trend analysis and benchmarking.[592] Jacobs' findings are provided at Attachment D17 to this revised proposal and their findings are summarised in this section.

Figure 4.2 and Figure 4.3 below (Figures A-8 and A-9 in the AER's draft decision) show repex for the period 2008-13 across the NEM normalised for customer density and capacity density.

Figure 4.2 Repex across the NEM normalised for customer density[593]



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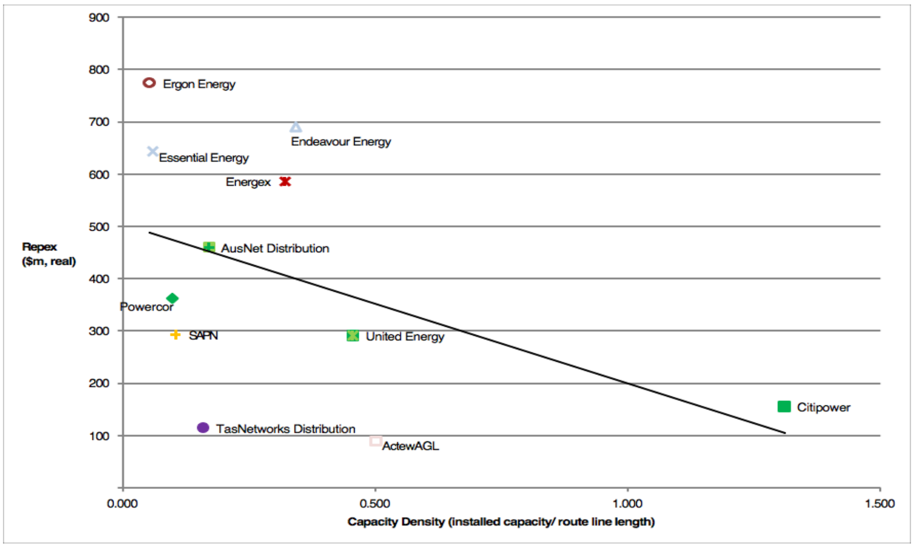
[592] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-46 to 6-54

[593] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-48

Figure 4.3 Repex across NEM normalised for capacity density[594]



These charts and associated commentary by the AER suggest that there is some relationship between the magnitude of repex for individual DNSPs and the customer density (customer/km line), as well as the capacity density (installed capacity/route line length). Such a proposition displays a lack of understanding of the nature of repex drivers, which are:

- the volumes and types of assets on the system;
- the overall age profile of the system assets as a whole;
- the overall condition and serviceability of the assets on the system, and any specific deficiencies in individual asset classes; and
- the estimated unit replacement cost of assets that have reached the end of their economic service life.

In addition, the AER appears to have misinterpreted the charts. For instance, the commentary under AER's Figure A-9 states:

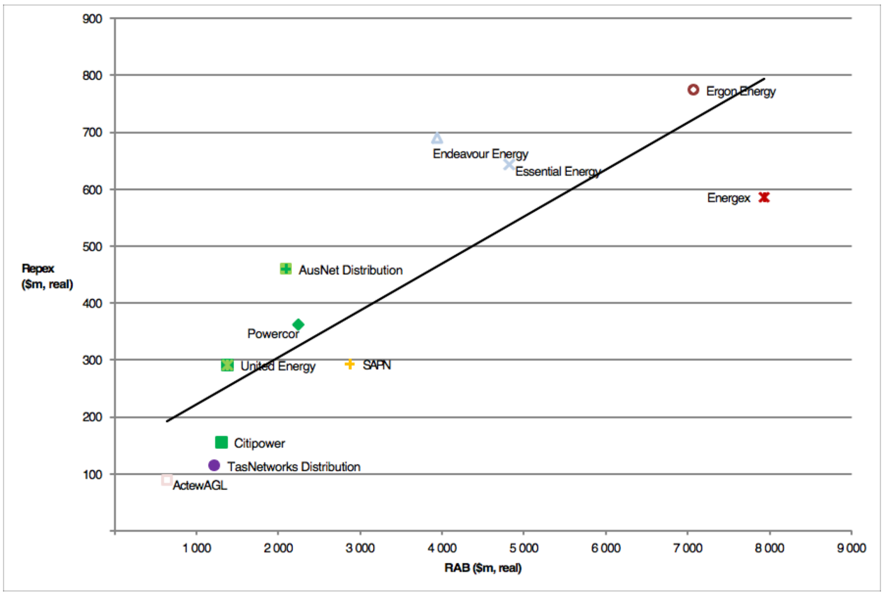
ActewAGL compares unfavourably under both density measures. Further, these measures suggest that predominantly rural based networks incur higher Repex than urbanised networks.[595]

[594] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-49

Clearly ActewAGL does not compare unfavourably under both measures, as it has the lowest level of repex of all DNSPs in Australia, as reflected on both Figure 4.2 and Figure 4.3.

The AER then presents the following Figure 4.4 (A-10 in Attachment 6 to the draft decision) showing the proportion of the asset base replaced during the 2008-13 period.

Figure 4.4 Proportion of asset base replaced in the 2008-13 period[596]



Jacobs agrees in theory with the AER's proposition that *"… the size of a service provider's regulatory asset base (RAB) will affect the amount of repex it incurs"* but notes that the RAB is not the most appropriate denominator to use in DNSP comparisons because:

- the RABs of Australian DNSPs were established at different points in time using different unit rate costs, and asset quantity data that was not always accurate; and

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[595] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-49

[596] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-50

- as a particular DNSP's network continues to age, the RAB of existing assets will decline (ignoring new assets added) due to additional depreciation. This will cause the DNSP's repex/RAB ratio to increase and fall above the average repex /RAB trend line (making it appear inefficient in respect of repex). In fact it is an indicator that the ageing system requires more repex to control the deteriorating age profile and declining asset condition, not less.[597]

Whilst ActewAGL Distribution accepts the relevance of the information shown in Figure 4.4 it does not accept the conclusion the AER draws from it. The AER concludes:

"Whilst we acknowledge the limitations outlined above, this measure indicates that ActewAGL has incurred average proportion of repex relative to the size of its RAB when compared with other service providers."[598]

This statement by the AER does not make sense. Figure and Figure 4.3 show very clearly that:

- ActewAGL Distribution had the lowest level of repex spend of any DNSP over the period 2008-13; and
- ActewAGL Distribution's repex over the period 2008-13 is well below the industry average trend line (by about 50 per cent).

A strong correlation is expected between repex and mean (weighted by replacement value) asset age. This was not benchmarked by the AER, although it has included some commentary on asset age. This correlation would be expected to show an increase in repex required as mean age increases (or mean remaining economic life decreases), and would also be impacted by local conditions facing DNSPs. The AER, in contrast, appears to expect that future repex should be similar to past repex, and uses this as a basis for refusing projected increases in repex funding.

Historic repex is not an appropriate basis for future repex requirements

The AER states in the draft decision that '*in our view, the long term trend provides a relevant baseline regarding ActewAGL's underlying repex requirements.'*[599]

ActewAGL Distribution fundamentally disagrees with the AER's premise that the future requirement for sustainable long term repex for a DNSP can be predicted by looking at the trend in past expenditure from 2003. Such an approach runs the risk of:

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[597] Jacobs, 2015, *Review of AER Draft Decision – REPEX, January 2015*, p. 7

[598] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-50

[599] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-47

- Failing to recognise where in the investment cycle each asset class sits, relative to the expected life of the asset class / type. i.e. whether the asset class has a relatively young average age relative to its life-cycle, reflecting the period in time when it was introduced on the system, or whether it is a mature class of assets with a high average asset age, and an age profile or deteriorating asset condition / reliability, which requires increasing replacement expenditure.
- Continuing to perpetuate an inadequate level of repex investment on the basis that the level of investment that has been made in the recent past is therefore adequate for the immediate future. This simplistic way of thinking fails to recognise that power systems in Australia will continue to age and deteriorate based on historical levels of repex (ActewAGL's system has aged 1.4 years in the past 5 years).
- Failing to respond to new and critical information about the ongoing serviceability and safety of certain asset classes. An example of this would be the findings and recommendations of the 2009 Victorian Bushfire Royal Commission (Royal Commission)600 that certain types of equipment and components on overhead distributions lines can contribute to an increased risk of starting a bushfire.

ActewAGL Distribution's repex for the 2014-19 regulatory period necessarily departs from expenditure in the 2009-14 regulatory because:

- It is now more economical to replace ActewAGL Distribution's underground cable assets than to incur increasing reactive maintenance expenditure;
- ActewAGL Distribution has shifted its asset management strategy from one of 'run to failure' to 'condition based monitoring' or 'age and condition based replacement' for some asset classes; and
- Expenditure on cross-arm replacement that was previously allocated to opex (as reactive maintenance) is now allocated to repex.

ActewAGL Distribution's repex program is supported by 'asset health'

The AER also suggested that measures of asset health do not support ActewAGL Distribution's proposed forecast replacement capex. The AER include a number of charts in the draft decision showing the asset age profile of poles, underground cables, service lines, transformers and switchgear.[601] The AER's charts have been derived from RIN data. ActewAGL Distribution notes

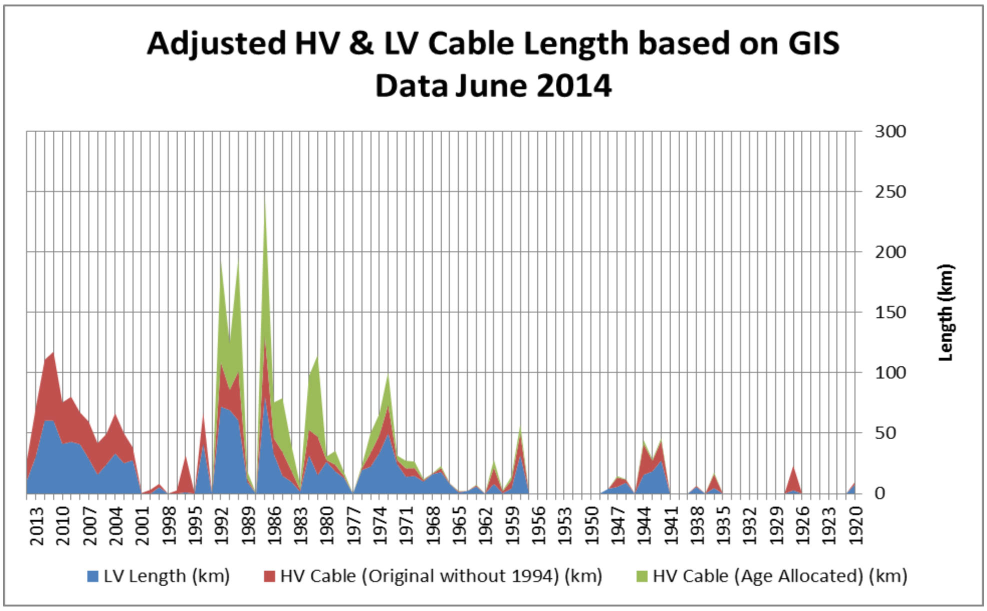
[600] See Attachment D16, Teague AO, B., McLeod AM, R. and Pascoe AM, S., 2010, *2009 Victorian Bushfires Royal Commission Final Report*, July 2010

[601] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, pp. 6-52 to 6-54

however that the RIN data has been sourced from systems containing asset age data that may not always be accurate for a number of reasons, and so does not provide a true picture of the age of ActewAGL Distribution's assets. In response to the AER's statement that 'ActewAGL's stock of older assets is low, with few assets still in service from the 1950s or earlier' ActewAGL Distribution notes the following:

- ActewAGL Distribution has approximately 165km of HV underground cable and 75km of LV underground cable which is older than 50 years.
- All 359 (approximately 0.7 per cent of total poles) of ActewAGL Distribution Stobie poles were installed before 1955.
- ActewAGL Distribution's Geographic Information System (GIS) was upgraded in 1994, at which time cables without a known installation date were migrated into the system with a default date of 1994. The cable assets have since been redistributed in the GIS based on the age of the suburb in which they are located, which provides a more appropriate age basis.
- An updated age profile of underground cables is provided in Figure 4.5 below showing HV and LV underground cables installed prior to the 1950s that remain in service.

Figure 4.5 HV and LV cable lengths by installation date



ActewAGL Distribution also strongly disagrees with the view by the AER that the 'high' level of asset replacement work undertaken in the last regulatory period would reduce the overall age of the network. Specifically, the AER states:

"… the historically high volume of asset replacement work that ActewAGL has carried out over the last five years is likely to have changed its asset age profile from five years ago. That is, by spending a large amount on repex in the last regulatory control period, ActewAGL is expected to have replaced a significant number of its older assets. This in turn may be expected to reduce the overall age of its network. If the average replacement life and the standard deviation stays the same, but the networks overall age is reduced, fewer assets will need to be replaced in the next period."

It is unclear to ActewAGL Distribution the basis on which the AER makes the conclusion that ActewAGL has carried out a 'high' volume of asset replacement work over the past five years. ActewAGL Distribution's ActewAGL repex during the 2009-14 regulatory period was $92.4 million,[602] only slightly higher than repex in previous regulatory period ($85.3 million[603]) and significantly less than the AER's regulated allowance for the 2009-14 period of $108 million. Figure 4.2 above clearly shows that ActewAGL Distribution's repex between 2008 and 2013 was about 50 percent below the average trend line for all benchmarked DNSPs.

In response to the AER's statement that asset replacement in the last regulatory period '*may be expected to reduce the overall age of its network….and…. fewer assets will need to be replaced in the next period*', ActewAGL Distribution refers the AER to section 1.3 of Appendix B17.1 of the subsequent regulatory proposal which clearly states that the weighted average age of the ActewAGL Distribution network increased from 24.88 years in 2007/08 to 26.3 years in 2012/13.

Finally, the AER also contends that ActewAGL Distribution's unplanned SAIFI, which measures the frequency of unplanned outages, has been kept at a steady level, below reliability targets from 2009 to 2013, which suggests that overall asset conditions have not deteriorated such as to justify increased repex. ActewAGL Distribution rejects this contention on the basis that forecast repex is dependent on the potential for asset failure, not the previous history of unplanned outages (SAIFI). This is because unplanned outages are influenced to some extent by asset condition, but are more highly correlated with weather and other environmental factors.

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[602] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 167

[603] ActewAGL Distribution 2008, ActewAGL Distribution Determination 2009-14 Regulatory Proposal to the Australian Energy Regulator, June 2008, p. 145. Total historic capex reported in Table 7.13 of $75.2 million ($2008/09) adjusted for inflation is equivalent to $85.3 million ($2013/14).

AER's predictive (repex) modelling results are invalid

ActewAGL Distribution does not rely solely on statistical modelling to generate its repex forecasts. Rather, it takes a more considered view of the condition of the assets as well as the likelihood and consequence of asset failure. In some cases, the consequence of asset failure can be severe and the replacement program is prioritised accordingly, notwithstanding the results of statistical modelling. This is an important component of ActewAGL Distribution's top-down forecasting assessment discussed in section 4.3.4 of this revised regulatory proposal.

The AER's alternative estimate for repex is based on the results of its predictive (calibrated repex) modelling. ActewAGL Distribution strongly rejects these forecasts because the results are invalid. The model uses incorrect quantity data and recalculates (or 'back-engineers') asset lives to produce a repex program that matches past repex expenditure. This assumption that past repex should be sufficient to meet future repex requirements is flawed, and discussed further below. Moreover, the asset lives generated by the model are typically in excess of standard industry asset lives.

ActewAGL Distribution notes also that the AER's deterministic approach to setting the repex forecasts based on the results of the calibrated repex model is completely inconsistent with the AER's explanatory statement for the *Expenditure Forecast and Assessment Guidelines* in which the AER states:[604]

It is likely we will use the repex model as a first pass model in future determinations, in combination with other assessment techniques. Initially, we will likely review proposed repex forecasts for all asset categories in detail, even those the repex model suggests are at reasonably efficient levels. This will help us to understand when we can rely on the repex model as a first pass model (and when we cannot).

Far from using the repex model as a first pass model in this determination, around 70 per cent of ActewAGL Distribution's propose repex has been subject to the repex model. The remaining 30 per cent of 'un-modelled' repex[605] has been subject to trend analysis despite some of this expenditure (for example, SCADA) being 'one-off' or 'lumpy' in nature. It is typically difficult to model these 'un-modelled' expenditure categories accurately by looking at recent historical expenditure.

[604] AER 2013, *Better Regulation Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, pp.282-283

[605] Unmodelled repex categories include overhead conductor and pole top structures, SCADA, control, protection etc. and other.

ActewAGL Distribution asked Jacobs to review the AER's base and calibrated repex models. Jacobs report is provided as Attachment D13 to the revised proposal. It highlights a number of significant shortcomings in the model, erroneous assumptions made by the AER and outcomes that simply don't make sense when considered in the context of ActewAGL Distribution's past expenditure on asset replacement. Indeed, these findings suggest to ActewAGL Distribution that the AER should be very cautious in 'relying on the repex model as a first pass model' let alone relying on it to deterministically set forecasts.

The AER's base case model incorporates replacement life information provided by ActewAGL in RIN submissions and generated two separate repex estimates. The first AER repex estimate was based on ActewAGL's observed costs in the past five years (historical unit cost), and the second repex estimate on costs derived from ActewAGL Distribution's forecast expenditure (forecast unit cost). The forecasts generated by the AER's base case repex model were $212 million and $206 million, respectively. ActewAGL Distribution notes that both forecasts are significantly higher than ActewAGL Distribution's forecast repex of $132.8 million ($2013/14) for the 2009-14 period.

Generally speaking, the asset replacement quantities derived by the AER's model are higher than what is reported in ActewAGL Distribution's RIN, which no doubt explains why the AER's outcomes are so much higher than ActewAGL Distribution's forecast repex for 2014-19.

As well as deriving incorrect forecast asset volume data, the AER's calibrated model is based on a set of 'calibrated average asset lives and standard deviations' that provides a similar (or lower) level of repex in the next regulatory period. Jacobs defines this process as 'back-engineering' of asset lives, and has advised ActewAGL Distribution that the exact nature of the calculation is not made clear in the repex model.[606] This model is based on the ill-founded premise that quantities and total replacement expenditure for each asset class in the previous regulatory period (as reported in the RIN) is adequate for future regulatory periods. This is simply not a valid assumption to make across all asset classes.

This appears to have strongly influenced the AER's thinking on, and prompted comments such as:

"The historically high volume of asset replacement work that ActewAGL Distribution has carried out over the last five years is likely to have changed its asset age profile from five years ago."[607]

The 'calibrated asset lives and standard deviations' applied by the AER are in some cases significantly higher than the asset lives assumed by ActewAGL Distribution in its own repex

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[606] Jacobs, 2015, *Focussed Critique of AER's REPEX – Calibrated model*, January 2015, p.7.

[607] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p6-61

modelling. For instance, whereas ActewAGL Distribution derived a mean life of 42 years and a standard deviation of 22 years from all available historic pole data, the AER applied a calibrated mean life of 71 years, and a standard deviation of 8.4 years, based on pole replacement volumes in the previous 5 years only. The AER's repex model has been similarly impacted by the AER selecting a much higher replacement life for underground cables (88.5 years compared to ActewAGL Distribution's 40 years). Because of the much higher asset lives assumed in most cases, the calibrated model generates forecasts for total repex of between $31 million and $71 million, significantly lower than ActewAGL Distribution's forecast $132.8 million ($2013/14).

Moreover, the Jacobs report highlights a number of examples where the AER's calibrated model generates outcomes that are completely inconsistent with sound engineering practice and ActewAGL Distribution's asset replacement strategies, some of which have previously been accepted by the AER. Specifically:

- The calibrated model proposes a significant reduction in the replacement of wood poles and an increase in wood pole staking, which does not reflect ActewAGL Distribution's strategy and cost/ benefit analysis for pole staking/pole replacement. The AER has separately indicated their acceptance of the ActewAGL Distribution pole staking and replacement strategies,[608] and pole replacement volumes[609] but has nevertheless still applied the results of the calibrated model (including pole replacement and staking).
- The calibrated model proposes a significant reduction in replacement volumes for medium and low voltage cables. This is contrary to ActewAGL Distribution's strategy for the replacement of oil filled cable pot heads, and a condition based replacement program for 11kV cables.
- The calibrated model adopts extraordinary asset replacement lives that far exceeds industry experience and are inconsistent with the practises of a responsible network operator. For example the model assumes an asset lives of 71 years for wood poles (compared to an industry average age of between 45 and 50 years), 89 years for HV underground cables (compared to accepted industry age of between 50 and 60 years), and up to 60 years for pole mounted transformers (compared to an industry average age of between 40 and 50 years).

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[608] AER 2008, *Draft Decision ACT Distribution Determination 2009-10 to 2013-14*, 7 November 2008, p. 74. On page 74 the AER states "*The AER considers ActewAGL's forecast pole replacement and reinforcement program is necessary and has been developed in accordance with sound policies and procedures.*"

[609] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p6-55. On page 6-55 the AER states "*our predictive modelling also supports the pole replacement volumes ActewAGL has proposed for the 2014-19 period*."

- The model proposed an increase in asset replacement volumes for steel and concrete poles which typically have an average life of between 55 and 60 years, but the average asset age for these categories are only 14 and 16 years respectively.
- The model also proposes an increase in the volume of high voltage cable replacements (66kv and 132kV), which ActewAGL Distribution has not identified as a critical asset management requirement.

AER's review of ActewAGL Distribution's major repex programs

This section sets out ActewAGL Distribution's response to the AER's concerns in respect of ActewAGL Distribution's key repex programs - underground cable replacement and overhead conductors and pole tops.

Underground cable replacement program

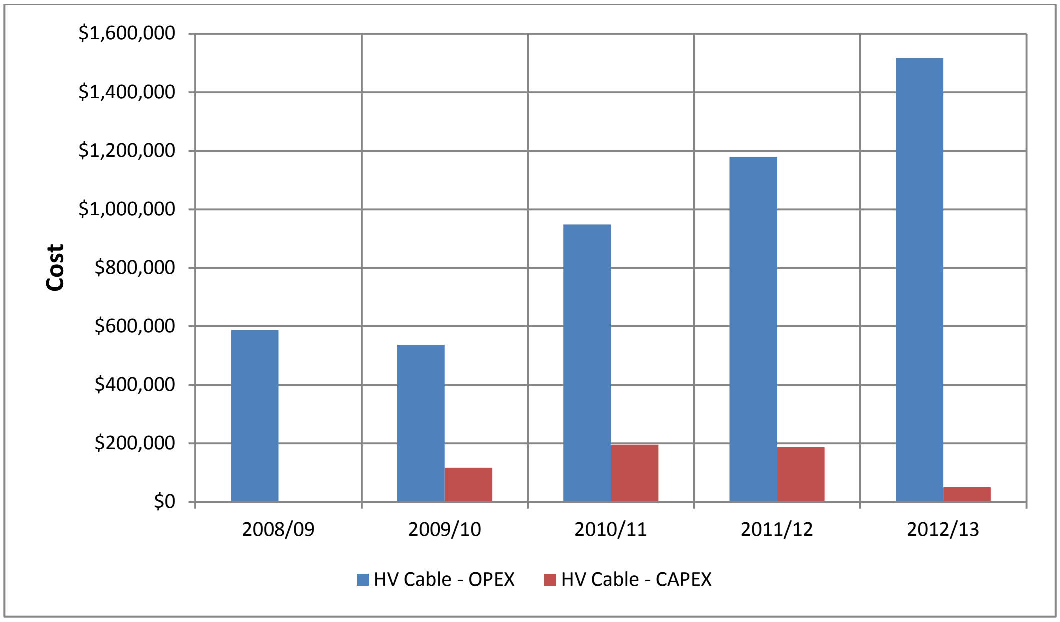
The AER rejected ActewAGL Distribution's proposed increase to its underground cable replacement program in the 2014-19 regulatory period on the basis that is has not justified the need for a threefold increase in expenditure on underground cable replacement compared to the 2009-14 regulatory period. Specifically, the AER observed:

- faults will be similar to the 2009-14 period and at worst will increase by one and a half times;
- ActewAGL Distribution has not explained the methodology it applied to derive the forecast rates; and
- ActewAGL Distribution hasn't provided economic justification for the change in its asset management strategy to support a significant increase in repex for underground cables.

ActewAGL Distribution's proposed increase in the underground cable repex is primarily driven by a change in the asset management strategy from one of 'run to failure,' under which replacement decisions have been driven by repeated root cause failure, to one of condition monitoring and planned replacement. There are 1,475km of high voltage underground cables in ActewAGL network, 12 percent of which are older than 60 years.

In the past 5 years, reactive repairs and replacements have been increasing, see Figure 4.6 below. Most repair work is on the cable joint or termination, and in undertaking this work it has been observed that an increasing number of underground cables are reaching the end of their life. This was observed on cables in the suburbs of Griffith and Kingston where the steel armour tape and the lead metallic sheath of the cable showed signs of corrosion during cable repairs. These cables were installed in 1943. Once the metallic sheath is compromised, moisture ingress into the cable will eventually lead to failure.

Figure 4.6 Underground cable reactive maintenance expenditure



ActewAGL Distribution considered three options for addressing the anticipated increase in underground cable failures in the 2014-19 regulatory period. These were:

- Maintain the status quo and accept the rising reactive maintenance cost.
- Replace all underground paper insulated cables over 60 years old and XLPE cables over 50 years old. If this strategy is adopted, over 175km will be due for replacement at an estimated cost of $43.7 million over the next five years.
- Initiate condition monitoring of underground cables and prioritise sections of the underground cable for replacement. Under this option, it was proposed to condition monitor 3 high voltage critical cables and feeders between 2014/15 to 2015/16 and 5 high voltage critical cables and feeders from 2016/17 and onwards. It was estimated that approximately 700 metres of cable section would be replaced in 2014/15 increasing to 4.5km of cable section replacement from 2015/16 and onwards.

Further details of ActewAGL Distribution's underground cable replacement program can be found in the project justification report,[610] Attachment D14 to this revised proposal. This

[610] ActewAGL Distribution, 2015, *HV Underground Cable Condition Assessment Project Justification Report*, January 2015

analysis shows that the third option above is the least cost option for addressing underground cable failures.

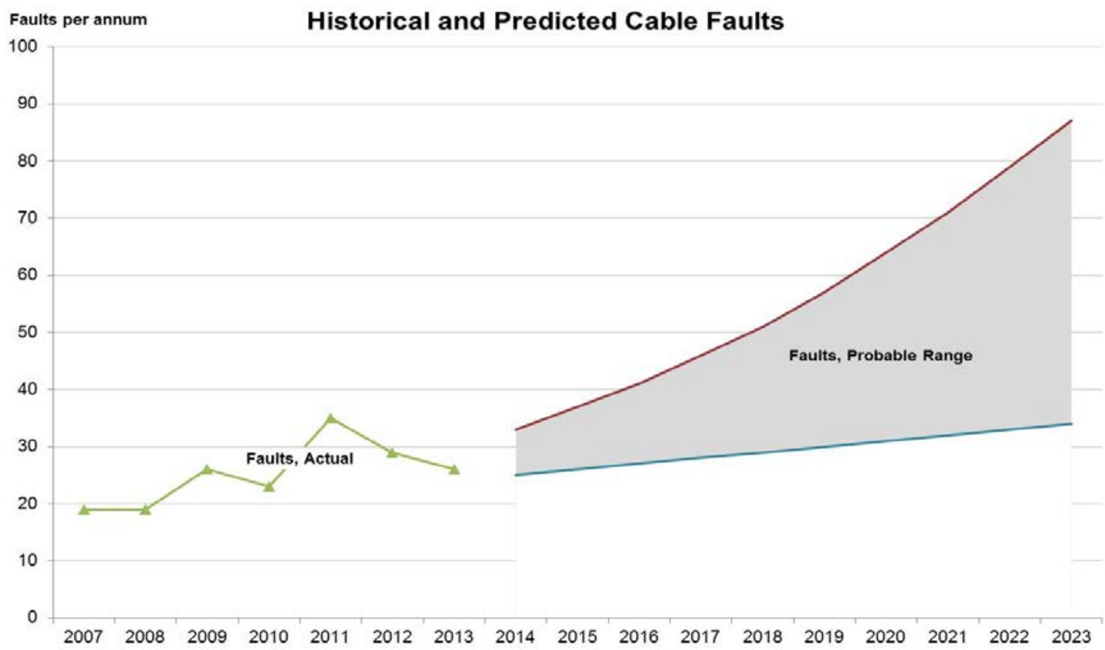
ActewAGL Distribution rejects the AER's concerns over the proposed increase in underground cable repex for the 2014-19 period on the basis that this increase is necessary to ensure that ActewAGL Distribution is able to meet its regulatory obligations in respect of reliability and security of electricity supply in the ACT. This program also represents the lowest cost option for addressing anticipated cable failures. ActewAGL Distribution's response to each of the AER's concerns is addressed below.

Forecast underground cable faults

The risk of failure for the cable fleet can be projected using asset age, assessed condition and expected remaining economic life. In particular:

- The failure point of an individual asset cannot be predicted accurately in advance, but mean failure rates across a fleet can be predicted with more certainty;
- Failure rates increase as assets age. Aside from unexpected failures attributed to faulty products or incorrect installation, young assets require less maintenance and will fail less than older assets. It should be noted that repex and maintenance costs do not remain constant through the life of an asset, and it is not reasonable to assume that future funding can be constrained to levels applying at some time in the past without affecting levels of service delivered.
- ActewAGL Distribution has a high proportion of underground cables compared to its peers, which needs to be taken into account when benchmarking. Approximately 27 per cent of this cable fleet will have exceeded its expected economic life by 2020, and projected failure rates are increasing. This is shown in Figure 4.7 below.

Figure 4.7 Historical and projected cable failure rates



This shows that overall; HV cable fault rate has been trending upwards since 2007. The fall in faults between 2011 and 2013 is considered an unexpected anomaly given the age profile of the assets, and is also attributed to the complete replacement of the 11kV Yamba feeder in 2013 which had been prone to failure. ActewAGL Distribution anticipates that under a run to failure strategy, as endorsed by the AER, there may be up to 64 high voltage cable faults per annum by 2020.

ActewAGL Distribution rejects the following statement made by the AER in the draft decision:

"At best the number of failures will be similar to the 2009–14 period and at worst will increase by one and a half times. ActewAGL did not provide any further information to indicate its expectations within the range of estimates. We do not consider this information supports an increase in failures in the 2014–19 period compared to the 2009–14 regulatory control period."[611]

The methodology ActewAGL Distribution has used to predict the failure rate is based on proven statistical analysis techniques and includes historical data and regression analysis to determine curves of best fit - one linear, one polynomial. The curves were used to forecast the expected

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[611] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p6-56

number of faults per annum. The linear curve formed to lower estimate, the polynomial formed the upper estimate.

Without the proposed increase in ActewAGL Distribution's underground cable replacement program there is a risk that the reactive maintenance cost forecasts will increase from the current $1.4 million ($2013/14) to a range of between $2.6 million and $7.2 million ($2013/14) in 2020, the average being around $5.4 million ($2013/14) with no corresponding reduction in future risk of cable failure.

This predicted failure rate, expressed as a risk of failure is shown in Figure 4.8 below, together with the capital budget that would be required based on a policy of renewal of critical assets at 99 percent of their nominal life:

- The solid line indicates the mean weighted risk of failure if renewals are not carried out;
- The dotted line shows the expected mean weighted condition of the fleet if the renewals are implemented as planned;
- The bars indicate the capital expenditure considered necessary to achieve the risk tolerance specified.

Figure 4.8 based on standard deterioration curves for this asset class. ActewAGL Distribution's experience with its own cables enables standard deterioration curves to be adapted to specific conditions and experience with these cables in the ACT. This has been used to derive ActewAGL Distribution's repex forecast for underground cables.

Figure 4.8 Replacement program and risk for underground cables (constant dollars)

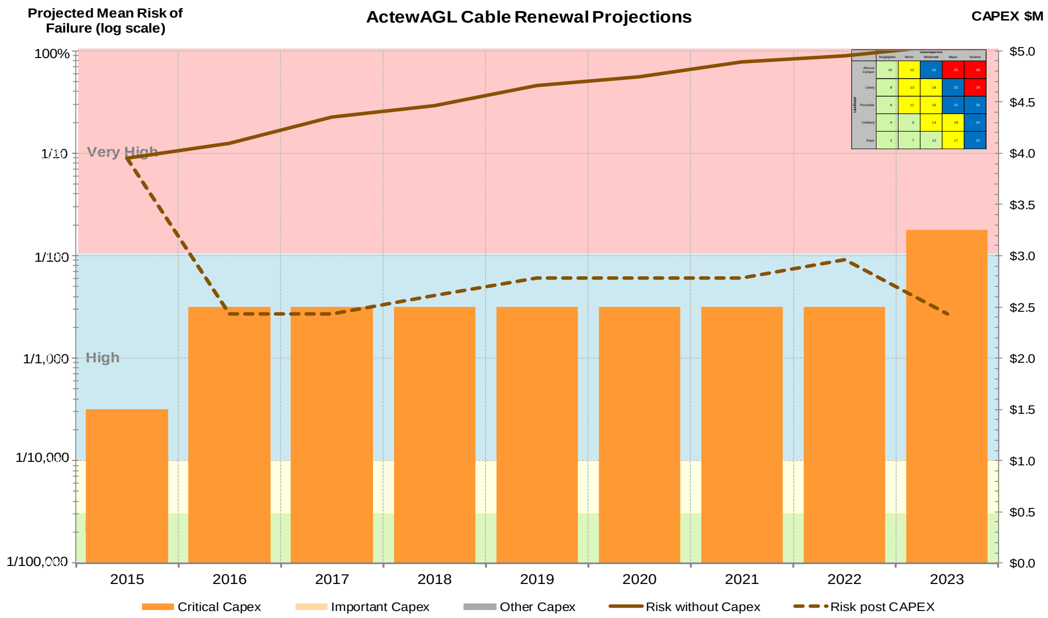


Figure 4.8 is also intended to illustrate the impact on risk to service of applying the AER's alternative estimate for repex. ActewAGL Distribution's proposal, represented by the dotted line would keep the risk of service interruption at around 1 in 100 (3.5 failures each year), whereas applying the AER's alternative repex estimate would result in service interruption during 2015 around 1 in 12 (approximately 30 failures in the year), and is projected to continue increasing if repex is deferred.

Forecast Methodology

The AER states in its draft decision that ActewAGL Distribution has not explained the methodology it applied to derive the forecast rate for underground cable failures. ActewAGL Distribution's method for forecasting high voltage underground cable faults is as follows:

- sample data used is the ActewAGL number of underground high voltage cable faults each calendar year from 2002 to 2013 (inclusive). Note that during this period; some old cables were replaced with new, which tends to reduce the fault rate in the sample data, making the model conservative;
- regression analysis was used to determine curves of best fit - one linear and one polynomial;
- these curves were used to forecast the expected number of faults per annum with the linear curve forming the lower estimate and the polynomial curve the upper estimate;
- the forecast fault rates were then used to determine the expected maintenance costs;

- fault rates will not be influenced by repairs to old cables, based on the repair to "bad as old" asset management analysis on patching aging systems; and
- the forecast failure rates are influenced by new cables replacing old cables in the future, calculated on a pro-rata basis ie. (km of old cable – km of new cable)/ (km of old cable).

ActewAGL Distribution's change in asset management approach

ActewAGL Distribution's historical practice has been to run underground cables to failure. The AER states:

'ActewAGL Distribution has not provided economic justification or cost-benefit analysis for this change in asset management strategy to support a significant increase in repex for this category.'[612]

Given the increase in reactive maintenance on underground cables during the 2009-14 period shown in Figure 4.6 and the forecast increase in expected faults under a 'do nothing' scenario shown in Figure 4.7, ActewAGL Distribution intends to change its asset management strategy for HV underground cables from 'run to failure' to condition monitoring with prioritised replacement. The project justification report attached to this revised proposal demonstrates that the change in strategy represents the least cost solution to addressing the projected increase in fault rates.

The forecast high voltage cable faults include all failure types, including:

- early life failure;
- random failures excluding all cable fault caused by third party and accidental damages; and
- deterioration failure.

The purpose of the condition based replacement program is to identify the high voltage cable feeder subjected to deterioration failure. The economic justification is based on the lifecycle cost analysis. When the cost rate of the run-to-failure / minimal repair is more than the condition based replacement cost rate, then the cable should be replaced. The results of the life cycle cost assessment of underground cables are provided in Box 4.1 below.

[612] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p6-56

Box 4.1 Life Cycle Cost Optimisation of Underground Cables

ActewAGL compared the cost of replacing cable based on condition with the cost of reactive work driven by cable failure.[8] A summary of the findings is presented below:

Cost ($m, constant dollars)	FY15	FY16	FY17	FY18	FY19
Condition Monitoring OPEX	$0.15	$0.15	$0.24	$0.24	$0.24
Cable Replacement CAPEX	$0.18	$1.13	$1.13	$1.13	$1.13
Condition Monitoring Total Cost	**$0.33**	**$1.28**	**$1.37**	**$1.37**	**$1.37**
Cable Reactive repair work OPEX	**$1.89**	**$1.33**	**$1.78**	**$2.29**	**$2.87**

It is clear that a strategy of cable replacement based on condition rating is the least cost solution, and therefore represents prudent and efficient OPEX and REPEX.

Overhead conductors and pole top structures

ActewAGL Distribution proposed repex of $10.5 million ($2013/14) on overhead conductors and pole top structures for the 2014-19 regulatory period. The AER considered that a *'repex allowance similar to the 2009-14 regulatory control period is sufficient to meet the capex criteria in the 2014-19 period*' and consequently proposed an allowance of $6 million ($2013/14), comprising $2.3 million for overhead conductors and $3.7 million for pole top replacement.[613]

The AER reduced ActewAGL Distribution's proposed forecast expenditure for overhead conductors and pole top structures on the basis that the:

'….proposed repex ….is more than three times higher for the 2014-19 period compared to what it spent….for the 2009-14 period.'[614]

ActewAGL Distribution's proposed repex on overhead conductors and pole top structures is not three times higher for than it was in the 2009-14 period. The AER's finding appears to be based on the following:

- There is a discrepancy between repex in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period for overhead and pole top structures ($10.5 million ($2013/14)), and repex reported in the RIN ($17.9 million ($2013/14) as some assets were double counted

[613] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-66

[614] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix A*, p. 6-57

in the RIN). The correct forecast is $10.5 million ($2013/14) as proposed in ActewAGL Distribution's regulatory proposal for the SRP;[615] and

- forecast repex on cross-arm replacement in 2014-19 of $1.1 million per annum was previously recorded as reactive maintenance opex in the 2009-14 regulatory.

Consequently, ActewAGL Distribution's proposed repex for overhead conductors and pole top structures in the 2014-19 period is approximately 1.75 times higher than for the 2009-14 period, not three time higher as suggested by the AER.

The AER also queried whether a failure rate of two potheads per year supports the need for replacing 50 per year over the next ten years. ActewAGL Distribution's response to the AER's concerns is set out in turn below.

ActewAGL Distribution's response to the AER's concerns in respect of proposed repex for overhead conductors and pole top structures is set out below.

Rural pole top upgrade

The failure of pole top hardware and cross-arms is a common form of failure on the overhead distribution system, and often causes the overhead conductors to sag excessively, or fall to the ground. The risk to public and worker safety is significant in such an event. Depending on the circumstances, the consequences can vary from "nil" to a worker or public fatality. This program is required to ensure the ongoing safety and serviceability of the overhead distribution system.

ActewAGL Distribution's rural pole tops upgrade program also provides a good example of why the AER's assessment of ActewAGL Distribution's forecast repex is flawed. The model's simplistic logic that repex in the past five years should be sufficient for the next regulatory period completely ignores important external considerations such as recommendations made by the 2009 Victorian Bushfire Royal Commission.

ActewAGL's rural pole top upgrade program was initiated in 2009 to replace deteriorating cross-arms and pole top hardware, and to install vibration dampers, armour rods, and preformed distribution ties on all rural high voltage overhead lines located in high bushfire risk areas. This program was triggered following the experience of other Australian power utilities where hand ties and conductor failures had been found to start bushfires. Recommendation 33[616] of the

[615] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 174.

[616] See Attachment D16, Teague AO, B., McLeod AM, R. and Pascoe AM, S., 2010, *2009 Victorian Bushfires Royal Commission Final Report*, July 2010, p.174

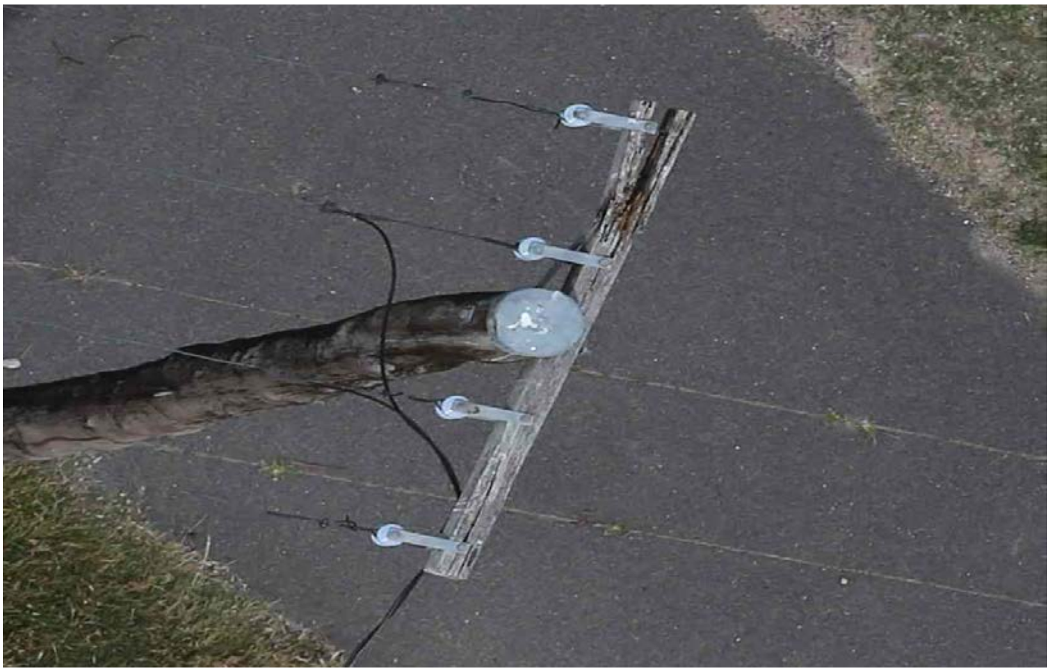
2009 Royal Commission which required all Victorian distribution businesses to fit or retrofit all spans that are more than 300 metres long with vibration dampers as soon as is reasonably practicable, further emphasised the importance of this program in bushfire prone regions of ActewAGL Distribution's network.

An inspection of ActewAGL Distribution crossarms in a bushfire prone region in March 2014 found a severely split cross arm, which only nine months previously had been inspected and found to be in serviceable condition.[617] The crossarm was at risk of failure and was immediately replaced. A visual inspection of the recovered crossarm showed that the internal rot and decay inside the crossarm may not be visually apparent until the deterioration had extended to the outer surface, at which point the cross-arm splits open. The following images provide a visual representation of the deterioration over a period of nine months.

Figure 4.9 Low Voltage pole off Cotter 11kV feeder (June 2013)

[617] At the time of inspection, this cross-arm displayed only weathering and a minor split.

Figure 4.10 Low Voltage pole off Cotter 11kV feeder (March 2014)



The prioritised repex program which includes upgrading the pole-top fittings and replacing deteriorated cross-arms, porcelain silicon carbide surge arresters, installing vibration dampers, armour rods, and preformed distribution ties, significantly reduces the risk of bushfires starting from the ActewAGL Distribution overhead system in high risk rural areas.

ActewAGL Distribution has identified the following rural feeders in bush fire prone areas as a high priority for replacement during the 2014-19 period.

- The remainder of the Cotter 11kV feeder – 18.1 km
- Mackenzie feeder – 27.3 km
- Lower Molonglo East & West feeder – 12.4 km
- Homann feeder –21.3 km
- Black Mountain feeder – 33.4 km

ActewAGL Distribution maintains that its forecast repex for the rural pole top upgrade is justified given the demonstrated potential for asset failure to result in bushfires in rural areas, as evidenced by the 2009 bushfires in Victoria and the subsequent recommendations from the Royal Commission in respect of vibration dampeners.

Finally, ActewAGL Distribution notes the concern raised by the Royal Commission in its 2010 Final Report about the impact of economic regulation on important asset replacement programs, with potentially catastrophic consequences. It stated:

'Victoria's electricity assets are ageing, and the age of the assets contributed to three of the electricity-caused fires … DNSP capacity to respond to an ageing network is, however, constrained by the electricity industry's economic regulatory regime. The regime favours the status quo and makes it difficult to bring about substantial reform. As components of the distribution network age and approach the end of their engineering life, there will probably be an increase in the number of fires resulting from asset failures unless urgent preventive steps are taken.

The Commission considers that now is the time to start replacing the ageing electricity infrastructure and to make major changes to its operation and management. The seriousness of the risk and the need to protect human life are imperatives Victorians cannot ignore. The number of fire starts involving electricity assets remains unacceptably high—at more than 200 a year.'

Pole top hardware renewal/cross-arm replacement

ActewAGL Distribution also carries out regular ground based surveys, and some aerial surveys to determine the condition and serviceability of cross-arms and pole top hardware in non-bushfire prone rural and urban areas.

Most pole top hardware requires renewal or refurbishment at least once or twice during the normal asset lifetime of the pole on which it is mounted. Only those pole-tops that are assessed as being in such a poor condition, that they are unlikely to remain in a safe state during the next routine inspection interval, are replaced. If the pole itself is assessed for replacement, then the pole top assembly is also replaced.

Where the pole remains in good condition and also meets other criterion (such as good accessibility, no black king bolt installed or split pole head), the deteriorated cross-arm is scheduled for replacement under the condition based cross-arm replacement program.

ActewAGL Distribution has a well established routine and proven pole-top assembly replacement and refurbishment program, and is not predicting any increasing quantities or unit rate costs. Historically, the majority of condition based cross-arm replacements were expensed and recorded as opex (reactive maintenance). However, all cross-arm replacement work is now allocated to capex because it represents an asset renewal. This appears to increase repex for 'overhead conductors and pole top structures' by $5.5 million over the 2014-19 period compared to the 2009-14, but this is offset by a corresponding decrease in opex for the period.

Jacobs has reviewed ActewAGL Distribution's pole-top assembly replacement/refurbishment program and considers it to be prudent and efficient.[618]

[618] Jacobs, 2015, Review of AER Draft Decision – REPEX, January 2015, p.12

Cast iron LV pothead replacement

The AER did not accept ActewAGL Distribution's proposed expenditure for overhead conductors and pole top structures, on the basis that an average failure rate of two pot heads per year does not support the need for replacing 50 per year over the next ten years, and that ActewAGL Distribution has not demonstrated the economic need for this change in activity.

ActewAGL Distribution has approximately 500 LV cast iron potheads on the distribution system, and the majority of them are located in residential back yards and highly populated areas. ActewAGL Distribution plans to replace 50 potheads per years over the next ten years. This is necessary for ActewAGL Distribution to meet its obligations under WHS legislation.

There have been several cases where a low voltage cast iron pothead has failed and exploded. In early 2014, shrapnel debris from a low voltage cast iron pothead explosion caused a near miss to an ActewAGL Distribution linesman who was working in the vicinity.

The explosive failure of these potheads is caused when pitch inside the pothead leaches out over time. As a result, the live internal terminal is exposed, and moisture and oxygen build up in the gaps. The lack of effective insulation causes a fault, and the fault energy causes the cast iron to explode.

The majority all of the cast iron potheads in the ActewAGL Distribution network are located in a public location. While they are mostly located in customers' backyards, some are located near schools and high pedestrian areas. The close proximity of the potheads to the public, and the explosive nature of failures impose an unacceptably high risk, with serious consequences.]

Most of the cast iron LV potheads were installed between 1968 and 1975 and have an expected life of between 25 and 40 years, making them all due for replacement. There are over 100 potheads located in areas such that the risk of injury is high to extreme.

ActewAGL Distribution rejects the AER's finding that the current average failure rate of 2 per year is not high enough to warrant an increase in replacement expenditure.

There were 13 cast iron LV pothead failures during the 2009-14 regulatory period. The current failure rate of 2 to 3 failures per year is significant, given the significant risk to personnel and public safety. This failure rate is expected to increase over the 2014-19 regulatory period given the age of the assets, and assuming the AER's draft decision is maintained.

Three options were considered to address the increasing safety risks associated with ageing cast iron LV potheads. They included:

1. Do nothing
2. Condition based replacement program
3. Phase out cast iron LV potheads

a. age based replacement program

b. risk based replacement program

ActewAGL Distribution's preferred option is to phase out all outdoor low voltage cast iron potheads located in public places over the next ten years. Under this option (3b), 25 potheads will be replaced each year based on their risk to public safety and a further 25 potheads will be replaced on an opportunity basis, for example when replacing other equipment.

To conclude, ActewAGL Distribution's asked Jacobs to review its overhead conductor and pole top structures repex programs. Jacobs concluded the following:

Jacobs considers that a 10 year period should be an adequate and appropriate timescale over which to undertake a major bushfire risk mitigation strategy such as that included within the 'Overhead conductor and pole top structures' category. The longer that such a mitigation program takes to implement, the greater the risk that a major bushfire incident will occur, resulting in potential criticism that the work should be been implemented more rapidly; and

Jacobs is of the view that ActewAGL Distribution has sound and justifiable reasons for proceeding with this replacement program as planned, and that is consistent with ActewAGL Distribution's safety obligations and responsibilities under the NER.'

Repex and Opex Interdependencies

The AER does not appear to have considered the inter-relationship between the AER's draft decision on repex and ActewAGL Distribution's resultant opex requirements over the 2014 -19 period. Whilst the AER observes that *'the amount of maintenance opex that is reflected in ActewAGL's opex base in part determines the extent to which ActewAGL Distribution needs to spend repex during the 2014-19 period'*,[619] the AER does not appear to have given effect to this proposition in determining either ActewAGL Distribution's repex allowance or its opex allowance for the 2014-19 period. It is not clear to ActewAGL Distribution that the AER has given any meaningful consideration to this inter-relationship between its repex decision and other constituent components of the draft decision, let alone sought to quantify the effect of its draft decision on repex for ActewAGL Distribution's required opex. This is discussed in section 2.6.3 of this revised proposal.

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[619] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-27

4.5.5 ActewAGL Distribution's repex program 2014-19

ActewAGL Distribution rejects the AER's alternative estimate for augex of $99.5 million ($2013/14) excluding overheads.

ActewAGL Distribution maintains its forecast capex for asset replacement and renewal, this being the amount required for ActewAGL Distribution to achieve the capex objectives. This is shown in Table 4.8 below.

Table 4.8 Forecast replacement and renewal capital expenditure 2014-19

($ million, 2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Zone Substations	2.0	1.2	2.1	1.7	1.7	8.8
Transmission	0.5	0.5	0.5	0.6	0.6	2.7
Distribution System	20.6	23.0	21.8	21.6	21.2	108.1
Secondary Systems	1.2	1.5	1.5	1.4	1.4	7.0
Property	1.6	1.5	1.5	1.6	0.0	6.1
Total replacement and renewal capital expenditure	**25.8**	**27.8**	**27.5**	**26.8**	**24.9**	**132.8**

4.6 Capitalised overheads

4.6.1 Overview

ActewAGL Distribution's proposed forecast total capex was based on capitalised overhead expenditure of $54.4 million ($2013/14).[620]

The AER did not accept ActewAGL Distribution's forecast capex for capitalised overheads for the 2014-19 period primarily because:[621]

- the AER's trend analysis disclosed that ActewAGL Distribution's proposed forecast capex for capitalised overheads as a proportion of total capex is not consistent with the 2.75 per cent average proportion of ActewAGL capitalised overheads to total capex in the 2009-2014 regulatory control period;

[620] In its Draft Decision, the AER refers to capitalised overheads of $52.2 million ($2013/14): AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, pp. 6-11 and 6-72. ActewAGL Distribution has not been able to reproduce this number and notes that, according to its RIN Table 2.1.1 and 2.1.5 accompanying its regulatory proposal for the SRP, ActewAGL Distribution's proposed forecast of capitalised overheads was $54.4 million ($2013/14) for the 2014-19 period.

[621] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, pp. 6-11 and 6-72 to 6-74

- ActewAGL Distribution's capitalised overheads should be lower because the AER has reduced 'base' opex, such that a lower amount of overheads needs to be capitalised; and
- ActewAGL Distribution's proposed forecast capex for capitalised overheads is not consistent with the AER's alternative estimate for forecast total capex.

ActewAGL Distribution contends that, in so deciding, the AER makes an error or errors of fact material to the making of its decision, incorrectly exercises its discretion in all the circumstances and makes a decision that is unreasonable in all the circumstances because:

- changes made to ActewAGL Distribution's corporate overheads allocation methodology with effect from 1 July 2014 by its revised Cost Allocation Methodology (CAM) approved by the AER in June 2013 (with which the Rules require ActewAGL Distribution's forecast total capex for 2014-19 period to be consistent) render the AER's trend analysis of limited probative value in assessing ActewAGL Distribution's forecast capex for capitalised overheads;
- the allocation of corporate costs to capex and opex projects is part of the opex cost build-up, which means that ActewAGL Distribution's 'base opex' is already adjusted for capitalised overheads; and
- in any event, ActewAGL Distribution rejects the AER's alternative estimates for opex and capex contained in the draft decision for the reasons explained in Chapter 3 and the remainder of this Chapter 4.

Therefore, ActewAGL Distribution proposes a revised forecast capex for capitalised overheads $52.3 million ($2013/14), this forecast being based on an allowance for capitalised overheads that is consistent with the revised capex and opex forecasts contained in this proposal and the revised CAM that came into effect from 1 July 2014.

4.6.2 ActewAGL Distribution's proposal

ActewAGL Distribution's proposed forecast total capex was based on a capitalised overhead expenditure of $54.4 million ($2013/14).[622]

ActewAGL Distribution explained in its regulatory proposal for the subsequent regulatory period that on 7 June 2013 the AER approved revisions to its CAM that were submitted to the AER by

[622] This was subsequently revised to $52.2 million in the RIN and submitted to the AER on 27 July 2014. In its Draft Decision, the AER refers to capitalised overheads of $52.2 million ($2013/14): AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, pp. 6-11 and 6-72. ActewAGL Distribution has not been able to reproduce this number and notes that, according to its RIN Table 2.1.1 and 2.1.5 accompanying its regulatory proposal for the SRP, ActewAGL Distribution's proposed forecast of capitalised overheads was $54.4 million ($2013/14) for the 2014-19 period.

ActewAGL Distribution on 20 December 2012, which revisions effected a change to ActewAGL Distribution's corporate overheads cost allocation methodology from 1 July 2014.[623] This change to the corporate overheads cost allocation methodology results in the direct allocation to projects of a greater proportion of corporate overheads, resulting in a higher proportion of overheads being capitalised rather than expensed.[624] ActewAGL Distribution's current CAM was attached to its regulatory proposal for the subsequent regulatory period.[625]

4.6.3 AER's draft decision

The AER did not accept ActewAGL Distribution's proposed forecast capex for capitalised overheads for the 2014-19 period of $54.4 million ($2013/14).[626] The AER instead included an amount of $7.6 million ($2013/14) in its alternative estimate for total capex for the period, representing a reduction to ActewAGL Distribution's proposed forecast in excess of 80 per cent.[627]

The AER undertook a trend analysis to 'assess ActewAGL Distribution's proposal by reference to the ActewAGL capitalised overheads it incurred during the 2009-2014 regulatory control period.'[628] It concluded that ActewAGL Distribution's proposed forecast capex for capitalised

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[623] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 221-222

[624] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 222

[625] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), Attachment B18 (Cost Allocation Methodology (December 2012))

[626] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, pp. 6-11 and 6-72. In its Draft Decision, the AER refers to capitalised overheads of $52.2 million ($2013/14). ActewAGL Distribution has not been able to reproduce this number and notes that, according to its RIN Table 2.1.1 and 2.1.5 accompanying its regulatory proposal for the SRP, ActewAGL Distribution's proposed forecast of capitalised overheads was $54.4 million ($2013/14) for the 2014-19 period.

[627] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, pp. 6-11 and 6-72

[628] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-72

overheads as a proportion of total capex is not consistent with the 2.75 per cent average proportion of ActewAGL capitalised overheads to total capex in the 2009-2014 regulatory control period.[629]

It also concluded that ActewAGL Distribution's forecast capex for capitalised overheads was not consistent with the reductions in other capex amounts included in the AER's alternative estimate of forecast total capex.[630]

Accordingly, the AER did not accept ActewAGL Distribution's forecast capex for capitalised overheads for the 2014-19 period because:[631]

- The increase in capitalised overheads for the 2014-19 period does not appear to have been supported by any changes to ActewAGL Distribution's capitalisation policy;
- ActewAGL Distribution's capitalised overheads should be lower because the AER has reduced 'base' opex, such that a lower amount of overheads needs to be capitalised; and
- ActewAGL Distribution's proposed forecast capex for capitalised overheads is not consistent with the AER's alternative estimate for forecast total capex.

The AER observed that it:

'expect[ed] ActewAGL to clarify in their revised regulatory proposal as to [sic] whether the increased overhead reflects any changes in its capitalisation policy from the 2009-14 regulatory control period'.[632]

The AER applied an overhead adjustment factor of 2.75 per cent in each year of the 2014-19 period, consistent with ActewAGL Distribution's historical trend.[633]

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[629] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, pp. 6-11 and 6-73 to 6-74

[630] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, pp. 6-11 and 6-74

[631] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-74

[632] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-11

[633] AER, ActewAGL Distribution Consolidated Capex Model/Overheads tab

4.6.4 ActewAGL Distribution's response

ActewAGL Distribution has not changed its policy with respect to the recording of costs as fixed assets versus expenses since the last regulatory period. However, as was explained in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period, revisions to its CAM approved by the AER in June 2013 changed its corporate overheads cost allocation methodology with effect from 1 July 2014, with the consequence that a greater proportion of its corporate overheads will be directly allocated to projects and thus capitalised rather than expensed in the 2014-19 period than were so allocated and expensed in the 2009-2014 regulatory control period.

Under ActewAGL Distribution's CAM that applied in the 2009-14 regulatory control period, corporate overhead costs are allocated to projects on the basis of time booked against projects in electronic or manual time sheets and the amount of corporate overheads allocated to capital programs was capped at 15 per cent of direct labour costs incurred.[634]

During the 2009-14 regulatory control period, ActewAGL Distribution engaged McGrathNicol Corporate Advisory (MGN) to review ActewAGL's CAM, with limited assurance provided by Deloitte. MGN found that the methodology used to allocate overhead costs to projects at that time did not best reflect the resources required to bring those projects to fruition. MGN recommended that ActewAGL Distribution adopt a CAM that uses total direct costs as the driver for allocating overheads across projects, and that this would more closely align with the cost allocation methodologies of other DNSPs.

Under the new CAM, all corporate overhead costs were fully absorbed by (or allocated across) all projects, and then regulated and unregulated activities and services, based on total direct (labour, materials and contractor) costs.[635] As such, the pool of costs to be absorbed is split into capex and opex categories based on the ratio of capital to operating projects over the regulatory year. Because the underlying capex program is typically higher than the opex program in monetary terms, this has resulted in a higher forecast allocation of overhead costs to capex in the 2014-19 regulatory period.

Table 4.9 below shows the split of corporate charges to opex and capex across the 2009-14 and 2014-19 regulatory periods. The percentage allocated to capex increased significantly in 2014 as

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[634] ActewAGL Distribution 2008, *ActewAGL electricity network cost allocation method ActewAGL submission to the Australian Energy Regulator*, February 2008, p. 7

[635] ActewAGL Distribution 2012, *ActewAGL Distribution Cost Allocation Methodology*, November 2012, p. 12 (being Attachment B18 to ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014))

a result of the change in ActewAGL Distribution's CAM, demonstrating the impact this change has had on the level of ActewAGL Distribution's capitalised overheads.

Table 4.9 Allocation of corporate service charges to capex and opex

Corporate Service Charges Analysis	2009-2014					2014-2019				
	Actual/ estimate ($000s nominal)					Forecast ($000s real June 2014)				
	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Standard Control Corporate Management Fee	10,517	12,621	15,156	12,796	16,712	0	0	0	0	0
Unregulated Services Services OPEX	172	167	179	266	455	2,104	1,726	1,627	1,663	1,744
Alternate Control Metering Services OPEX	215	203	231	295	300	895	971	932	968	1,116
Standard Control Services OPEX	3,238	3,416	3,192	3,822	4,011	9,824	10,302	9,519	9,991	10,611
Alternative Control Metering Services CAPEX	171	149	195	245	262	917	257	243	250	263
Standard Control Services CAPEX	1,829	1,592	2,081	2,611	2,378	10,222	9,957	11,128	10,897	10,091
Total Corporate Service Charges	16,143	18,149	21,034	20,034	24,118	23,962	23,213	23,449	23,769	23,826
Capital Expenditure	2009-2014					2014-2019				
	Actual/ estimate ($000s nominal)					Forecast ($000s real June 2014)				
	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Standard control services capex	70,288	80,413	74,995	79,372	95,364	80,439	69,627	78,103	75,241	70,237
Alternative control services capex	3,772	4,103	4,090	4,464	4,426	6,138	1,625	1,618	1,630	1,648
Total Capital Expenditure	74,061	84,517	79,085	83,836	99,790	86,577	71,252	79,721	76,871	71,885
Corporate Service/Capital Program	3%	2%	3%	3%	3%	13%	14%	14%	15%	14%
Operating Expenditure	2009-2014					2014-2019				
	Actual/ estimate ($000s nominal)					Forecast ($000s real June 2014)				
	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Standard control services opex	60,552	69,171	72,232	76,408	85,157	74,835	74,222	72,349	74,265	75,562
Alternative control services opex	2,977	3,037	3,502	3,495	3,475	5,988	6,143	6,194	6,317	6,992
Total Operating Expenditure	63,528	72,208	75,734	79,903	88,632	80,824	80,365	78,543	80,582	82,554
Corporate Service/Operating Program	22%	22%	25%	21%	24%	13%	14%	13%	14%	14%

ActewAGL Distribution contends that it follows from the change to its corporate overheads cost allocation methodology with effect from 1 July 2014, as a consequence of the revisions to its CAM approved by the AER in June 2013, that its historic and forecast overhead capitalisation rates are not comparable and, thus, the trend analysis conducted by the AER is of limited probative value in assessing ActewAGL Distribution's forecast capex for capitalised overheads.

ActewAGL Distribution observes that the Rules require its forecast total capex for the 2014-19 period to be in accordance with the principles and policies set out in its approved revised CAM[636] and its forecast overhead capitalisation rate of 14 per cent (on average) is consistent with ActewAGL Distribution's current CAM.

[636] See, for example, clause 6.5.7(b)(2) of the Rules.

Further, ActewAGL Distribution's forecast overhead capitalisation rate is at the lower end of capitalisation rates set by the AER for the three NSW DNSPs (between 13 and 31.9 per cent).[637]

Overhead adjustment factors set by the AER for ActewAGL Distribution and the NSW DNSPs are shown in Table 4.10 below.

Table 4.10 Comparison of AER capitalised overhead adjustment factors

Capitalised Overheads %	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Endeavour Energy Proposal	16.2	17.3	20.6	20.5	21.7
AER draft decision	13.0	13.0	13.0	13.0	13.0
Essential Energy Proposal	32.4	34.7	34.6	35.6	35.8
AER draft decision	31.9	31.9	31.9	31.9	31.9
Ausgrid Proposal	17.58	17.20	16.67	16.78	16.70
AER draft decision	18.34	18.34	18.34	18.34	18.34
ActewAGL Distribution Proposal	**12.8**	**14.25**	**13.11**	**14.94**	**14.88**
AER draft decision	**2.75**	**2.75**	**2.75**	**2.75**	**2.75**

Despite this, the AER has set an overhead 'adjustment factor' of just 2.75 per cent for ActewAGL Distribution in each year of the 2014-19 period. In so doing, the AER has made an error or errors of fact that are material to its decision, incorrectly exercised its discretion in all the circumstances and made a decision that is unreasonable in all the circumstances.

Further, the AER's contention that capitalised overheads should be lower because the AER has reduced 'base' opex suggests that the AER does not understand how ActewAGL Distribution's CAM is applied. The allocation of corporate costs to capex and opex projects is part of the opex cost build-up, that is, ActewAGL Distribution's 'base' opex has already been adjusted for capitalised overheads.

In any event, ActewAGL Distribution rejects the AER's alternative estimates for opex and capex contained in the draft decision for the reasons explained in Chapter 3 and the remainder of this Chapter 4. For this reason also, ActewAGL Distribution contends that the AER errs in concluding

[637] AER 2014, *Draft Decision Ausgrid Determination: Attachment 6*, pp. 6-110 to 6-112 and Ausgrid Consolidated Capex Forecast Model – November 2014/Overheads Tab; AER 2014, *Draft Decision Endeavour Energy Determination: Attachment 6*, pp. 6-102 to 6-104 and Endeavour Consolidated Capex Forecast Model – November 2014/Overheads Tab; and AER 2014, *Draft Decision Essential Energy Determination: Attachment 6*, pp. 6-76 to 6-77 and Essential Consolidated Capex Forecast Model – November 2014/Overheads Tab

that ActewAGL Distribution's forecast capex for capitalised overheads does not reasonably reflect the capex criteria.

Therefore, ActewAGL Distribution proposes a revised forecast capex for capitalised overheads $52.3 million ($2013/14), this forecast being based on an allowance for capitalised overheads that is consistent with the revised capex and opex forecasts contained in this proposal and the revised CAM that came into effect from 1 July 2014.

4.7 Real cost escalation

4.7.1 Overview

ActewAGL Distribution proposed to use real cost escalators specific to various asset classes developed for it by SKM (now Jacobs) in forecasting capex for the 2014-19 period.[638]

The AER accepted ActewAGL Distribution's proposed labour and construction cost escalation as proposed by ActewAGL Distribution is being likely to more reasonably reflect a realistic expectation of the cost inputs required to achieve the capex criteria given these are direct inputs into the cost of providing network services. However, the AER rejected ActewAGL Distribution's proposed material cost escalators on the basis that:

- the degree of the potential inaccuracy of commodities forecasts is such that we consider that zero per cent real cost escalation is likely to provide a more reliable estimation for the price of input materials used by ActewAGL to provide network services
- there is little evidence to support how accurately ActewAGL's materials escalation model forecasts reasonably reflect changes in prices paid by ActewAGL for physical assets in the past and by which we can assess the reliability and accuracy of its forecast materials model. Without this supporting evidence, it is difficult to assess the accuracy and reliability of ActewAGL's material input cost escalators model as a predictor of the prices of the assets used by ActewAGL to provide network services, and

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[638] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 163-166; SKM 2013, *Assessment of Efficiency of Unit Rates for Selected Activities*, 20 November 2013 (Attachment B11 to ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014))

- ActewAGL has not provided any supporting evidence to show that it has considered whether there may be some material exogenous factors that impact on the cost of physical inputs that are not captured by the material input cost models used by ActewAGL.

ActewAGL Distribution rejects the AER's findings on material cost escalation for the following reasons:

- The AER's proposed approach which is to apply zero percent escalation on the basis that it is too difficult to forecast real material cost changes with any accuracy, amounts to applying a forecast (of zero percent) without any evidentiary justification.
- By contrast, ActewAGL Distribution's material cost escalation forecasts were prepared by SKM (now Jacobs) using an approach that has been accepted by the AER in past revenue determinations and is applied and accepted by regulators, governments, financial institutions in Australia and in other jurisdictions.
- ActewAGL Distribution's material cost escalation model is unbiased. The AER's contention to the contrary is addressed by ActewAGL Distribution in section 4.7.4 below and critiqued by Jacobs in Attachment D15 to this revised proposal.

4.7.2 ActewAGL Distribution's proposal

ActewAGL Distribution proposed to use real cost escalators specific to various asset classes developed for it by SKM (now Jacobs) in forecasting capex for the 2014-19 period.[639]

SKM developed these real cost escalators using real cost escalation indices for the following cost drivers calculated for ActewAGL Distribution by CEG for the 2014-19 period:[640]

- aluminium;

[639] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 163-166; SKM 2013, *Assessment of Efficiency of Unit Rates for Selected Activities*, 20 November 2013 (Attachment B11 to ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014))

[640640] CEG 2013, *Escalation factors affecting expenditure forecasts*, December 2013 (**CEG Report**) (Attachment B12 to ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014))

- copper;
- steel;
- crude oil; and
- construction, both engineering and non-residential; and
- annual labour cost escalators specific to the ACT for the 2014-19 period developed for ActewAGL Distribution by Independent Economics.[641]

On the basis of the above raw material input price escalators, Jacobs calculated escalation factors specific to various asset classes by applying a percentage contribution, or weighting, by which each of the underlying cost drivers were considered to influence the total price of each asset and taking into account foreign exchange movements to convert the price of international commodities that are typically quoted in USD.[642] In determining the appropriate weighting of cost drivers for network assets, Jacobs drew on a wide range of information including its knowledge of commercial rise and fall clauses contained within confidential network procurement contracts signed by Jacobs during market price surveys, information passed on during its interviews with equipment suppliers and manufacturers and industry knowledge held by a large internal pool of professional estimators, Engineering Procurement and Construction Management (EPCM) project managers, economists, engineers and operational personnel.

In total, Jacobs calculated annual real cost escalation indices for 15 of ActewAGL Distribution's standard asset classes.[643]

[641] Independent Economics 2013, *Labour cost escalators for NSW, the ACT and Tasmania*, 16 August 2013 (Attachment B13 to ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014))

[642] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 164-165

[643] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 164-165

4.7.3 AER's draft decision

The AER did not accept either ActewAGL Distribution's proposed materials cost escalation or its proposed labour cost escalation for use in forecasting capex for the 2014-19 period.[644] The AER does, however, accept ActewAGL Distribution's proposed construction cost escalation.[645]

With respect to ActewAGL Distribution's proposed materials cost escalation, the AER concluded that it could not be satisfied that the material input costs model used by ActewAGL Distribution would result in material costs estimates that reasonably reflect the capex criteria, including in particular a realistic expectation of the cost of inputs in the 2014-19 period required to achieve the capex objectives as required by clause 6.5.7(c)(3) of the Rules.[646] The AER is concerned that there is insufficient evidence before it to enable it to be satisfied that ActewAGL Distribution's model, which uses forecast changes in the prices of the commodities (i.e. copper, aluminium, steel and crude oil) that are raw inputs to the manufactured materials utilised in a distribution network (e.g., poles, cables and transformers), will derive unbiased and reliable forecasts of the costs of those manufactured materials.[647]

Specifically, the AER concludes that it cannot be satisfied that ActewAGL Distribution's material input costs model produces reliable and unbiased forecasts of real materials cost changes because:

- ActewAGL Distribution has not adduced any evidence to demonstrate the accuracy of its material input costs model in forecasting changes in the historical prices of manufactured network materials, notwithstanding that the AER noted the importance of such evidence in its Expenditure Forecast Assessment Guideline;[648]
- ActewAGL Distribution has not adduced any evidence of the extent to which the price of manufactured network materials, such as cables and transformers, are correlated with raw

[644] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, pp. 6-11 to 6-12 and *Appendix E*, p. 6-103

[645] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix E*, p. 6-103

[646] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix E*, p. 6-103

[647] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix E*, p. 6-114

[648] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix E*, pp. 6-103 and 6-106 to 6-107

material input costs, the derivation of the commodity input weightings for each asset class that are intended to represent this relationship or the existence or otherwise of material exogenous factors (such as changes in technologies, changes to suppliers' sourcing of commodity inputs and the volatility of exchange rates) affecting the price of manufactured network materials, again notwithstanding that the AER noted the importance of such matters in its Guideline. In particular, the set of commodity inputs included in ActewAGL Distribution's model may not be inclusive of all inputs that affect the price of manufactured network materials and may have been selected so as to produce an upward bias in resultant forecasts of changes in those prices;[649]

- the application of the commodity input weightings for each asset class may overstate the increase in overall input costs and result in an upward bias in material costs escalation because those weightings do not reflect the potential for mitigation of increases in materials costs through:[650]
    - commodity input substitution by ActewAGL Distribution and the supplier of manufactured network inputs provided there are no technically fixed input proportions;
    - substitution between opex and capex in response to changes in commodity input prices; and
    - economies of scale resulting from increases in the scale of ActewAGL Distribution's business;
    - increases in productivity not taken into account by ActewAGL Distribution in forecasting capex for the 2014-19 period; and
    - hedging strategies or the inclusion of price escalation provisions in their contracts for the supply of manufactured network materials;
- the following economic literature suggests that there is likely to be significant uncertainty in forecasting commodity input price movements:[651]

[649] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix E*, pp. 6-106 to 6-107 and 6-109

[650] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix E*, pp. 6-107 to 6-109

[651] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-12, and *Appendix E*, pp. 6-108 and 6-114

- the economic literature on the usefulness of commodities futures prices in forecasting spot prices, which suggests that forecasts of commodity prices based on futures prices perform better than 'no change' forecasts only for some commodities and some forecast horizons; and
- the economic literature on exchange rate forecast models, which suggests a 'no change' forecasting approach may be more accurate than the forward exchange rate produced by these forecasting models.

The AER asserts that views expressed and evidence relied on in the CEG Report relied on by ActewAGL Distribution, and in reports prepared by SKM and BIS Shrapnel for TransGrid and Jemena Gas Networks respectively and submitted by them to the AER in their concurrent regulatory reviews, support its conclusions above.[652]

In addition, the AER concludes that:[653]

- real materials cost escalation is inconsistent with the incentive based nature of the regulatory regime, as it results in a forecast of total capex that is cost based to a greater degree; and
- as the 2009 commodities boom experienced in Australia has subsided, there is now diminished justification for escalating for real materials costs changes in forecasting capex.

The AER concludes that it cannot determine a robust alternative forecast of real cost escalation for materials, presumably based on the economic literature suggesting that a 'no change' forecasting approach may perform as well as forecasts of commodity prices based on futures prices and exchange rate forecast models, and, in these circumstances, real materials cost escalation should not be applied in determining a service provider's required capex.[654] The AER, therefore, concludes that zero real materials cost escalation will better contribute to a forecast of ActewAGL Distribution's total capex that reasonably reflects the capex criteria and, thus, the AER does not escalate for real materials costs in deriving its alternative estimate of total capex for the 2014-19 period.[655]

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[652] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix E*, pp. 6-109 to 6-114

[653] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix E*, p. 109

[654] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix E*, pp. 6-114 to 6-115

[655] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-12, and *Appendix E*, pp. 6-103, 6-106 and 6-114 to 6-115

By contrast, the AER concludes that labour and construction cost escalators can be more reliably and robustly forecast than materials cost escalators because:[656]

- labour and construction cost escalators are not derived by reference to intermediate inputs;
- productivity improvements are factored into the derivation of labour escalators; and
- construction cost escalators can be forecast with greater precision because the drivers of those costs (being construction and manufacturing wages, plant equipment and other fabricated metal products, and plant and equipment hire) are reasonably transparent and can be predicted with some degree of accuracy.

With respect to labour cost escalation, however, the AER concludes that an average of the forecasts for the electricity, gas, water and water services sectors from each of Deloitte and Independent Economics should be used to forecast labour price change for the 2014-19 period is to be preferred to ActewAGL Distribution's proposed use of Independent Economics' forecasts because, historically, an average of these forecasts has better reflected ActewAGL labour prices for these sectors.[657] The AER's reasoning in support of this decision is discussed in greater detail in section 3.5.3 of Chapter 3 of this revised regulatory proposal.

4.7.4 ActewAGL Distribution’s response

ActewAGL Distribution’s response to the AER’s findings on labour cost escalation is provided in section 3.6.4 of this revised proposal. ActewAGL Distribution’s labour cost escalators have been updated since ActewAGL Distribution submitted its regulatory proposal for the subsequent regulatory period to take account of prevailing economic conditions. Independent Economics’ updated labour cost escalators are provided at attachment C46. These escalators have been used by CEG to develop real cost escalators, provided at attachment C47.

ActewAGL Distribution strongly rejects the AER’s proposed approach to materials cost escalation which is to apply zero percent escalation on the basis that it is too difficult to forecast real material cost changes with any accuracy. ActewAGL Distribution contends that such an approach is, in essence, applying a forecast (of zero percent) but without any evidentiary justification whatsoever. That is, the AER provides no evidence that a ‘no change’ forecast of real materials costs is as likely to be accurate and reliable as any attempt to forecast the change in those costs.

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[656] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6: Appendix E*, p. 6-115

[657] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-12

By contrast, ActewAGL Distribution's material cost escalation forecasts were prepared by Jacobs using an approach that has been accepted by the AER in past revenue determinations and is applied and accepted by regulators, governments, financial institutions in Australia and in other jurisdictions. Over the past decade, Jacobs has developed a material cost escalation modelling process which captures the impact of forecast movements of specific input cost drivers on future electricity infrastructure pricing, providing robust material cost escalation rates. Jacobs' method has been applied extensively to electricity transmission and distribution assets for close to a decade.

Commodity based material cost escalation a well-established regulatory technique

ActewAGL Distribution asked Jacobs to review the AER's findings on real material cost escalation in the draft decision. Jacobs report forms Attachment D15 to this revised proposal and documents Jacobs experience over the past decade in respect of material cost escalation, demonstrating the significant amount of research and analysis that has gone into developing and maintaining Jacobs' modelling process and capturing the likely impact of input cost drivers on future electricity infrastructure prices.[658] Jacobs experience in this area includes the following:

- Jacobs (then SKM) was engaged by Energex in 2010 to provide a set of suitable cost escalation rates for Energex's capex and opex programs of work. Energex had received an unsatisfactory response from the AER in relation to the cost escalation rate modelling proposed by its consultants during its initial regulatory submission, and engaged Jacobs to provide modelling for its revised submission. ***The Jacobs escalation rates were received favourably by the AER.***
- In July 2007, Jacobs (then SKM) was engaged by the Australian Energy Regulator (AER) to review the regulatory revenue proposal submitted by ElectraNet for their next regulatory reset period 2008 to 2013. During this assignment the Jacobs' model was both updated and enhanced through consideration of elements presented by ElectraNet. ***The AER again accepted the Jacobs view to cost escalation index design***.
- Jacobs (then SKM) was engaged by SP AusNet to analyse the likely drivers of cost escalation on capital expenditure forecasts over the remaining two years of their current determination (2006/07 and 2007/08), and for the next regulatory reset period (2008/09 to 2012/13, commencing 1 April 2008). The SP AusNet assignment set the precedent for above CPI escalation of capex costs. ***The AER accepted the Jacobs methodology noting that it produced robust figures for the purpose intended.***

Moreover, during the recent commodity boom, Jacobs was able to successfully demonstrate that DNSP capital costs are strongly linked to commodity prices of steel, copper and aluminium. This

[658] Jacobs 2015, *ActewAGL – Cost Escalation Factors Commodity Price Forecasting*, 14 January 2015, pp.10-13.

linkage has not changed and supports the development of a robust forecast of real material costs.

ActewAGL Distribution notes the AER's proposal to apply zero real cost escalation to materials because it is 'too difficult' is inconsistent with its own previous decisions on material cost escalation. Specifically, in its draft decision on ActewAGL Distribution's regulatory proposal for the 2009-14 period, the AER stated:

In light of these external factors, it was considered that cost escalation at CPI no longer reasonably reflected a realistic expectation of the movement in some of the equipment and labour costs faced by electricity network service providers (NSPs).[659]

The AER continued to apply material cost escalation rather than CPI escalation in its final decision of the Victorian Electricity Distribution Network Service Providers for the 2011-2015 determination in October 2010. Specifically,

Materials cost escalation - Consistent with appendix K, the AER's final decision is to apply the steel escalators to the unit costs of public lighting poles and brackets,89 weighted by 45 per cent to reflect only the purchase price for steel.[660]

In its 2010 determination on the South Australian Electricity Distribution Business, the AER's recommendation for materials cost escalation included the use of London Metals Exchange (LME) forward contract prices for 63 months and 123 months for aluminium and copper.[661]

AER's departure from material escalation unfounded

Jacobs has reviewed the AER's arguments for moving away from material cost escalation in the draft decision and concludes that the AER has not advanced 'adequate reasons for departing from previous accepted methodologies.'[662] In particular, Jacobs states:

Jacobs firmly believes, in line with other reputable forecasters in the private and public sectors, that using a composite basket of weighted indices, appropriate and specific to the cost item in question, to

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[659] AER, 2008, Draft Decision *ACT Distribution Determination 2009-10 to 2013-14*, 7 November, 2008 p. 230. This position was maintained by the AER in its 2009 Final Decision.

[660] AER Final decision - Victorian electricity distribution network service providers Distribution determination 2011–2015, October 2010

[661] AER Final decision – South Australian Distribution Determination 2010-11 to 2014-1, May 2010

[662] Jacobs 2015, *ActewAGL – Cost Escalation Factors Commodity Price Forecasting*, 14 January 2015

forecast price movements of that cost item is both robust and more reliable than use of a single index based on projections of price movements in a non-representative basket of consumer goods.

As the Regulator the AER should not accept unsubstantiated statements, comments or views, nor should the AER give unsubstantiated statements, comments and views. We consider that the AER has not substantiated their departure from the previous forecasting approach.[663]

While the AER states that forecasting commodity prices is marked by 'potential inaccuracy', ActewAGL Distribution considers that this 'potential for inaccuracy' is true of any forecasting technique including the forecasting of CPI. It is therefore not appropriate for the AER to throw aside a previously established and accepted method for escalating material costs in favour of a CPI (zero real) based forecasting approach, unless it can be demonstrated that this is more accurate. Jacobs makes the following statement on dealing with 'potential inaccuracies':

'…. the AER's statement, that because of potential errors, there is no value in applying cost forecasts (other than CPI) can be deemed to be a non sequitur: using the premise that there are potential inaccuracies with commodity forecasts to conclude that escalation should not be applied is inappropriate. Rather, we consider it more appropriate to decide whether or not to apply commodity escalation on the basis of whether the relevant projections are more often right (in terms of being in the vicinity of percentage changes in ActewAGL price movements over time) than wrong. Further, we note future CPI assumptions are also forecasts, but based on a basket of goods that is not representative of electricity DNSPs' cost bases.

Indeed, we consider that one way to address or ameliorate inaccuracies in any particular forecast index is through using composite indices (which are typically a mix of different commodity, labour and other costs). Composite indices can compensate for individual commodity spot fluctuations by means of a portfolio averaging effect.'[664]

ActewAGL Distribution's material cost input model is not biased

ActewAGL Distribution strongly rejects the AER's adverse contention that ActewAGL Distribution's material cost input model may be biased. Specifically, the AER states:

The limited number of material inputs included in ActewAGL's material input escalation model may not be representative of the full set of inputs or input choices impacting on changes in the prices of assets purchased by ActewAGL. ActewAGL's materials input cost model may also be biased to the

[663] Jacobs 2015, *ActewAGL – Cost Escalation Factors Commodity Price Forecasting*, 14 January 2015

[664] Jacobs 2015, *ActewAGL – Cost Escalation Factors Commodity Price Forecasting*, 14 January 2015

extent that it may include a selective subset of commodities that are forecast to increase in price during the 2014-2019 period.[665]

ActewAGL Distribution asked Jacobs to comment specifically on this AER contention. Jacobs' complete response is contained in Attachment D15 to this revised proposal, but can be summarised as follows:

The Jacobs model is based on the following primary factors which are considered to influence cost movements- base metals such as copper, aluminium and steel, oil, construction costs; and foreign exchange. These cost drivers were selected following a multi-utility strategic procurement study which researched contract information for main items of plant equipment and materials (such as power transformers, switchgear, cables and conductors) together with contract cost information for turn-key substation and overhead line projects (including plant equipment, materials, construction, testing and commissioning).

Developing the specific weighting by which each of the input cost drivers are considered to influence the total cost of the various asset categories is achieved through an application of information that exists within the Jacobs model as well as from client input and input from major supplies – such as transformer manufacturers. The weightings applied are periodically adjusted to take account of any divergence in the cost escalation of constituent components of utility assets over time. This is an important step in ensuring that no bias is introduced into the weighting process in the long term.

Over the last ten years Jacobs has undertaken a substantial number of assignments across a number of DNSPs and TNSPs and other utilities (water, rail etc.) developing these composite indices. Drawing on the data obtained during these assignments and referencing market price survey data provided by the various Australian DNSPs Jacobs has been able to refine the commodity weightings to develop material cost escalators that minimise, if not negate bias, compared to other techniques.

We also consider the use of composite indices that are validated through back-casting and whose weightings are periodically adjusted for variances in long term escalation of the constituent indices is less prone to bias than applying a forecast single non-specific escalator such as movement in forecast CPI.[666]

To conclude, ActewAGL Distribution considers that the AER has not advanced sufficient information in support of a CPI (zero real forecast) based approach to escalation. ActewAGL

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[665] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 6*, p. 6-154

[666] Jacobs 2015, *ActewAGL – Cost Escalation Factors Commodity Price Forecasting*, 14 January 2015.

Distribution's revised material cost escalators are provided in Attachment C46 to this revised proposal.

4.8 ActewAGL Distribution's revised regulatory proposal for capex

ActewAGL Distribution rejects the AER's alternate estimate for capex for the 2014-19 regulatory period. In this revised proposal, ActewAGL Distribution has provided additional information as requested by the AER to substantiate the efficiency of its proposed capex forecasts. It has also identified a number of material errors in the analysis conducted by the AER, particularly with respect to its repex modelling which is based on incorrect data and yields invalid results, which led it to conclude that ActewAGL's forecast total capex was inconsistent with the capex criteria.

In the process of responding to the AER's contentions, ActewAGL Distribution has also corrected some discrepancies in the data it had previously reported to the AER.[667] ActewAGL Distribution has also reviewed the need for, scope and timing of its major augmentation projects, and has revised its total forecast capex to $341 million ($2013/14), to reflect reductions in augmentation capex.

This revised capex allowance is required to achieve the capex objectives specified in clause 6.5.7(a) of the Rules. ActewAGL Distribution considers that its revised total forecast capex is consistent with the capex criteria in the Rules, and reflects the efficient expenditure necessary for ActewAGL Distribution to continue to meet its regulatory obligations in respect of safety and service levels.

ActewAGL Distribution also considers that its proposed capex forecast appropriately takes into account the interaction between opex and capex, and will ensure the ongoing safety, security and reliability of the network. In contrast, the AER's draft decision reduces both ActewAGL Distribution's forecast opex and its forecast repex, without taking into account the interactions between repex and opex, or the impact on safety, service levels, security of supply and reliability.

[667] Specifically: (i) revisions to the non-network capex amount due to the discrepancies identified by the AER between the figures in the PTRM and that in the RIN templates; (ii) a double-counting by ActewAGL in its RIN response of replacement expenditure relating to overhead conductors and pole top structures.

ActewAGL Distribution's revised forecast for total capex by category for the 2014-19 regulatory period is set out in Table 4.11 below.

Table 4.11 ActewAGL Distribution's revised total forecast capex

($million, 2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Asset renewal/replacement	25.8	27.8	27.5	26.8	24.9	132.8
Customer initiated	19.1	18.5	16.3	17.7	20.2	91.8
Augmentation	8.5	10.6	22.8	22.5	15.3	79.8
Reliability and Quality Improvements	1.6	1.5	2.7	1.9	0.2	7.9
Network IT Systems	11.3	1.7	1.2	0.8	1.8	16.8
Less Capital Contributions	(5.9)	(6.0)	(5.3)	(5.8)	(6.7)	(29.8)
Less Disposals	0.0	(0.9)	(1.0)	(0.5)	(0.4)	(2.9)
Non-system assets	11.2	7.5	6.2	3.3	5.8	34.0
Corporate Services Business Support	3.1	2.0	1.5	2.2	1.9	10.7
Total capital expenditure	**74.5**	**62.6**	**71.8**	**69.0**	**63.1**	**341.0**

5 Demand and consumption forecasts

5.1 Introduction

In this Chapter 5, ActewAGL Distribution responds to the AER's draft decision on demand and consumption forecasts for the 2014-19 period set out in Appendix C - Demand to Attachment 6: Capital Expenditure to the AER's draft decision (Capex Appendix C).

The AER's draft decision is to:

- accept that the system demand forecasts proposed in ActewAGL Distribution’s regulatory proposal for the subsequent regulatory period reasonably reflect a realistic expectation of demand; and
- not accept ActewAGL Distribution’s proposed consumption forecasts and to therefore conclude that those forecasts are not appropriate inputs into the PTRM.

The AER notes four concerns regarding ActewAGL Distribution’s consumption forecasting method and states its view that ActewAGL Distribution should undertake further testing in relation its assumption about energy efficiency schemes (see section 5.4.3 below). However, the AER states that it does not have concerns about ActewAGL Distribution's consumption models and forecasts for the Residential off-peak (OP) category.

The AER then determines alternative consumption forecasts for the purposes of ActewAGL Distribution's distribution determination.

ActewAGL Distribution has updated its demand forecasts for use by the AER in its final decision using the method utilised in its regulatory proposal for the subsequent regulatory period (see Attachment H17).

ActewAGL Distribution contends that the AER errs in rejecting ActewAGL Distribution's consumption forecasts for the reasons set out in section 5.4.4. ActewAGL Distribution maintains that its consumption forecasts are appropriate inputs into the PTRM and that the AER should accept ActewAGL Distribution's forecast methodology and apply it in its final decision.

ActewAGL Distribution contends that the AER is unable to rely upon its alternative forecasts which have been developed internally using a model selection process that results in the AER's forecast method being statistically inferior to ActewAGL Distribution’s proposed forecast method (see sections 5.4.4.2 and 5.4.4.3 below).

ActewAGL Distribution engaged Jacobs to review the AER’s comments on ActewAGL Distribution’s consumption forecast method. Jacobs’ report is attached as Attachment E3 to this revised regulatory proposal and the key findings of that report are detailed below.

5.2 *The relevant legal and regulatory framework for demand and consumption forecasts*

5.2.1 The NEO and the RPPs

ActewAGL Distribution refers to and repeats the discussion of the relevance and role of the NEO and the RPPs in section 3.2.1 above.

5.2.2 Constituent decisions on opex and capex, and other inputs

ActewAGL Distribution refers to and repeats the discussion of the relevant constituent decisions on which the distribution determination for ActewAGL Distribution for the subsequent regulatory period is predicated in sections 3.2.2 and 4.2.2 above.

There is an additional constituent decision on which the distribution determination for ActewAGL Distribution for the subsequent regulatory period is relevantly predicated, namely, a decision in which the AER decides other appropriate amounts, values or inputs under clause 6.12.1(10) of the Rules. Demand and consumption forecasts, being key inputs to the making of other constituent decisions such as the decision under clause 6.12.1(11) on the X factors for the purposes of ActewAGL Distribution's average revenue cap, are the subject of this additional constituent decision on other appropriate amounts, values or inputs under clause 6.12.1(10).

5.2.3 The capex and opex criteria, objectives and factors

ActewAGL Distribution refers to and repeats the discussion of the capex and opex criteria, capex and opex objectives and opex and capex factors in sections 3.2.3 and 4.2.3 above.

In particular, meeting or managing the expected demand for standard control services over the 2014-19 period is one of the capex objectives and opex objectives that the AER must consider when assessing ActewAGL Distribution's regulatory proposal and making its constituent decisions in relation to forecast capex and forecast opex respectively under clause 6.12.1(3) and (4) of the Rules.[668]

In addition, the Rules require the AER to determine forecasts of ActewAGL Distribution's required opex and capex for the 2014-19 period that it is satisfied reasonably reflect the opex criteria and capex criteria respectively, which relevantly include (amongst other things)

[668] *National Electricity Rules,* clauses 6.5.6(a)(1) and 6.5.7(a)(1).

"*a realistic expectation of the demand forecast and cost inputs required to achieve the [opex/capex] objectives*."[669]

5.3 Demand forecasts

5.3.1 Overview

The AER has accepted that the system demand forecasts in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period reasonably reflect a realistic expectation of demand. Accordingly, ActewAGL Distribution has updated its demand forecasts for use by the AER in its final decision using the method utilised in its regulatory proposal for the subsequent regulatory period (see Attachment E1).

5.3.2 ActewAGL Distribution's proposal

ActewAGL Distribution's regulatory proposal for the subsequent regulatory period included peak demand forecasts developed by ActewAGL Distribution and independently verified by Jacobs.[670]

5.3.3 AER draft decision

The AER concludes that it is "*satisfied the system demand forecasts in ActewAGL's regulatory proposal for the 2014-2019 period reasonably reflects a realistic expectation of demand*."[671]

The AER observes that its decisions should reflect the most current expectations of the forecast period and accordingly that it "*will consider updated demand forecasts and other information in the final decision to reflect the most up to date data.*"[672]

Despite being satisfied with ActewAGL Distribution's system demand forecasts, the AER observes that ActewAGL Distribution "*has not modelled the future impacts of energy efficiency measures, demand side participation and demand management*".[673]

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[669] *National Electricity Rules,* clauses 6.5.6(c)(3) , 6.5.7(c)(3) and 6.12.1(3)(ii) and (4)(ii).

[670] ActewAGL, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period*, *Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), Attachment C1 (Peak demand forecast) and Attachment C2 (Review of demand forecast methodology).

[671] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-82

[672] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-83

5.3.4 ActewAGL Distribution's revised regulatory proposal

Applying the same methodology that ActewAGL Distribution used to derive the demand forecasts in its regulatory proposal for the subsequent regulatory period that has been accepted by the AER, ActewAGL Distribution has updated its peak demand forecasts to reflect the most current expectations in respect of the forecast period. These updated forecasts have been independently verified by Jacobs (see Attachment E2). The accuracy of the previous demand forecasts was also updated at a zone substation level and appropriate adjustments have been made to the forecasts of those zone substations that had an error of greater than ±5 per cent in 2013-14. Further detail on the derivation of the updated forecasts is set out in Attachment E1.

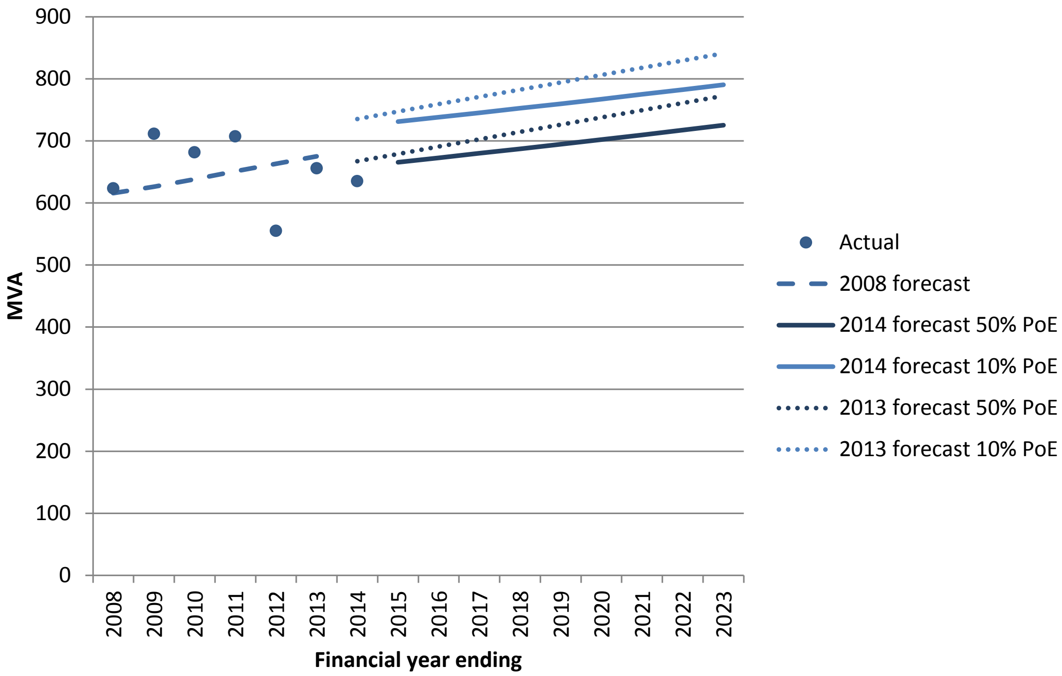
ActewAGL Distribution's updated weather-corrected forecasts of system summer maximum demand are presented in Figure 5.1. This Figure is the updated version of Figure 5.2 included in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period.[674] It shows both the 2013 forecasts included in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period and the 2014 forecasts that form the basis of ActewAGL Distribution's revised proposal.

In 2013, system maximum demand growth had been forecast to continue at around 12 MVA per annum in the then forthcoming 2014-19 period. Following lower-than-forecast outcomes in 2013-14, this forecast growth has been revised downwards to 7-8 MVA or 1.1 per cent per annum in this revised regulatory proposal.

[673] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-83

[674] For further explanation of Figure 5.1, see ActewAGL, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period*, *Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), page 105

Figure 5.1: System summer maximum demand forecasts



5.4 Consumption forecasts

5.4.1 Overview

The AER concludes that it is not satisfied that ActewAGL Distribution's consumption forecasts represent appropriate amounts, values or inputs for the purposes of making ActewAGL Distribution's distribution determination. The AER considers that ActewAGL Distribution's forecasts are not appropriate inputs into the PTRM due to four concerns it has regarding ActewAGL Distribution's consumption forecasting method.

The AER therefore determines its own alternative consumption forecasts for the purposes of ActewAGL Distribution's distribution determination.

5.4.2 ActewAGL Distribution's proposal

ActewAGL Distribution engaged Jacobs SKM (now Jacobs) to identify key factors influencing electricity consumption in the ACT and to prepare an independent report on energy sales forecasts for the ACT electricity network for the 2014-19 period. Jacobs was selected as it has considerable expertise and experience in developing network energy forecasts and advising on energy forecasting methods.[675]

The consumption forecasts were developed by Jacobs following a detailed and robust investigation of numerous candidate models and an objective model selection process that was, as noted by the AER in its draft decision,[676] transparently described.

Following Jacobs' application of model selection criteria focusing on model fit (as measured by R2 and the Akaike Information Criterion (AIC)), the preferred models were determined as follows:

- for residential general purpose (GP), a model using employment per person to predict zero efficiency consumption per person, with efficiency savings applied ex post;
- for residential OP, a fixed rate per year using the rate from 2008 to 2013;
- for non-residential low-voltage (LV), a model using State Final Demand and interest rates to predict zero efficiency consumption, with efficiency savings applied ex post; and
- for non-residential high-voltage (HV), a model using State Final Demand to predict zero efficiency consumption, with efficiency savings applied ex post.[677]

Finally, projections of the selected explanatory variables were used to prepare a forecast for the period 2014-19. ActewAGL Distribution commissioned BIS Shrapnel to provide these projections.

Energy savings were projected by Jacobs based on AEMO projections for the effect of Commonwealth schemes and the expected additional impact of the Energy Efficiency (Cost of Living) Improvement Act 2012 implemented in the ACT.[678]

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[675] ActewAGL, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period*, *Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), Attachment C3 (Trends in ACT electricity consumption).

[676] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-89

[677] ActewAGL, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period*, *Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), pages 108 to 109

[678] ActewAGL, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period*, *Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), page 109

5.4.3 AER draft decision

The AER concludes that it is not satisfied that ActewAGL Distribution's consumption forecasts represent appropriate amounts, values or inputs for the purposes of making ActewAGL Distribution's distribution determination.[679]

The AER states that it is satisfied that ActewAGL Distribution's broad approach is consistent with common industry practice.[680] However, the AER expresses the following concerns regarding ActewAGL Distribution's consumption forecasting method:[681]

- ActewAGL Distribution's model selection suffers from the biasing effects of autocorrelation;
- ActewAGL Distribution's preferred models do not include price as an explanatory variable;
- ActewAGL Distribution's specification of the dependent variable in its preferred models are not in 'per customer' terms;[682]
- ActewAGL Distribution did not consider the drivers of customer forecasts, such as changes in the profile of customers, in sufficient detail.

Nonetheless, the AER states that ActewAGL Distribution's consumption models and forecasts for the Residential OP category are reasonable and the above concerns do not apply to them.[683]

The AER also concludes that ActewAGL Distribution should conduct tests to ensure it has not double-counted energy efficiency schemes, particularly for the Residential GP category where energy efficiency has a strong effect.[684]

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[679] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-87

[680] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-89

[681] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, pages 6-89 to 6-91

[682] However, the AER states that this concern is not applicable to the Commercial HV category - see AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-91

[683] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-89

[684] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, pages 6-89 and 6-91 to 6-92

As a result, the AER concludes that ActewAGL Distribution's forecasts are not appropriate inputs into the PTRM.[685] The AER therefore determines alternative consumption forecasts that it considers represent appropriate amounts, values or inputs for the purposes of making ActewAGL Distribution's distribution determination.

5.4.4 ActewAGL Distribution's response

5.4.4.1 *Overview*

The AER has not provided sufficient reasons for rejecting ActewAGL Distribution's consumption forecasts.

The AER notes it retained the services of an econometrician to assist it in its analysis of ActewAGL Distribution's consumption forecasts, but it does not provide details of that assistance including the name of the econometrician, whether that econometrician is an independent, suitably experienced expert or details of the analysis undertaken by that econometrician.[686] When ActewAGL Distribution requested that information, it was informed that the AER had engaged the econometrician under a secondment agreement to undertake a brief desktop review and provide a verbal report.[687] ActewAGL Distribution was not provided by the AER with any file note or other record of that verbal report notwithstanding the AER's obligation under section 28ZJ of the NEL to keep a record of decision related matter in making a distribution determination including any material considered by the AER in making that determination.

ActewAGL Distribution has therefore been unable to have its expert, Jacobs, consider the relevant econometrician's advice and opinions in responding to the AER's draft decision on consumption forecasts in preparing this revised regulatory proposal. The AER has therefore failed to afford procedural fairness to ActewAGL Distribution and is accordingly unable to rely upon the views of the relevant econometrician in making its distribution determination for ActewAGL Distribution.

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[685] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-87

[686] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-88

[687] Letter from Usman Saadat, Manager Regulatory Affairs of ActewAGL Distribution to Mr Warwick Anderson, General Manager Network Regulation of the AER dated 5 December 2014 and email of response from Kurt Stevens of the AER to Bjorn Tibell, Senior Financial Advisor of ActewAGL Distribution dated 10 December 2014.

ActewAGL Distribution has therefore prepared its response based on its understanding that the views expressed by the AER in Capex Appendix C are the AER's own and are not supported by any opinion from an independent, suitably experienced expert.

Against this background, ActewAGL Distribution observes that:

- the AER's alternative forecast was developed using a subjective model selection process in which it "*selected the models with widely accepted explanatory variables and reasonable coefficient values*",[688] rather than selecting models on the basis of statistical evidence. In particular, the AER's forecast includes the outputs of models discarded as part of Jacobs' objective model selection process;[689] and
- statistical evidence shows the models used by the AER to develop its alternative forecast are inferior to those proposed by ActewAGL Distribution (see Section 5.4.4.3 below).

ActewAGL Distribution contends that, in rejecting ActewAGL Distribution's consumption forecast, the AER makes an error or errors of fact material to the making of its decision, incorrectly exercises its discretion in all the circumstances and/or makes a decision that is unreasonable in all the circumstances.

Therefore, ActewAGL Distribution maintains its forecast method proposed in its regulatory proposal for the subsequent regulatory period in this revised proposal and contends that this method, and not that of the AER, produces consumption forecasts that are appropriate inputs for use in making ActewAGL Distribution's distribution determination.

If the X factors were to be set based on the AER's draft decision on consumption forecasts, but outturn consumption was in line with the forecast proposed by ActewAGL Distribution in this revised proposal, outturn revenue would fall short of the revenue requirement by 3.7 per cent over the period 2015-16 to 2018-19. Given the evidence in this chapter that ActewAGL Distribution's forecast is preferable, the AER's draft decision is therefore inconsistent with Section 7A(2) of the NEL as it would deny ActewAGL Distribution a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services.

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[688] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-92

[689] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, pages 6-92 to 6-93

ActewAGL Distribution responds to each of the AER's specific concerns with ActewAGL Distribution's consumption forecasting method[690] in turn in sections 5.4.4.2 to 5.4.4.6 below.

5.4.4.2 *The AER's view that ActewAGL Distribution's model selection suffers from the biasing effects of autocorrelation*

The AER states its view that ActewAGL Distribution's approach to selecting the preferred models is not appropriate due to the presence of autocorrelation in two of ActewAGL Distribution's preferred models, which models the AER does not specify.[691] ActewAGL Distribution rejects the AER's view and contends that its model selection does not suffer from the biasing effects of autocorrelation.

In an attempt to understand the reasons for the AER's view, ActewAGL Distribution and Jacobs have re-run the candidate regression models for the Residential GP, LV and HV markets and extracted the Durbin Watson test statistic to confirm whether any of the models suffer from autocorrelation problems as the AER asserts.[692]

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[690] However, the AER states that it does not have concerns about ActewAGL's consumption models and forecasts for the Residential OP category - see AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-89

[691] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-90

[692] See Attachment E3, Jacobs, 2015, *Response to AER on its draft determination on ACT energy forecasts, ActewAGL*, January, page 11 and Attachment H1, *Durbin Watson tests*

Table 5.1: Outcomes from Durbin-Watson tests for autocorrelation

Model	*DW statistic*	*5% dL*	*Test outcome for Positive Autocorrelation*	*Test outcome for Negative Autocorrelation*
R7	2.80	0.91	No positive autocorrelation	Inconclusive
R8	1.84	0.91	No positive autocorrelation	No negative autocorrelation
R9	1.98	1.05	No positive autocorrelation	No negative autocorrelation
R10	1.71	0.91	No positive autocorrelation	No negative autocorrelation
R11	2.94	1.05	No positive autocorrelation	Inconclusive
R12	2.36	0.91	No positive autocorrelation	No negative autocorrelation
R13	1.87	0.91	No positive autocorrelation	No negative autocorrelation
R14	2.72	0.91	No positive autocorrelation	Inconclusive
R15	1.53	1.05	No positive autocorrelation	No negative autocorrelation
R16	2.88	1.05	No positive autocorrelation	Inconclusive
R17	1.79	0.91	No positive autocorrelation	No negative autocorrelation
LV1	1.84	0.91	No positive autocorrelation	No negative autocorrelation
LV2	1.72	0.91	No positive autocorrelation	No negative autocorrelation
LV3	1.32	0.91	Inconclusive	No negative autocorrelation
LV4	1.12	1.05	Inconclusive	No negative autocorrelation
LV5	0.76	0.91	Evidence for positive autocorrelation	No negative autocorrelation
LV6	1.80	0.91	No positive autocorrelation	No negative autocorrelation
LV7	1.92	0.91	No positive autocorrelation	No negative autocorrelation
LV8	1.66	1.05	No positive autocorrelation	No negative autocorrelation
LV9	0.80	0.91	Evidence for positive autocorrelation	No negative autocorrelation
LV10	0.63	1.05	Evidence for positive autocorrelation	No negative autocorrelation
HV1	0.96	1.05	Evidence for positive autocorrelation	No negative autocorrelation
HV2	1.33	0.91	Inconclusive	No negative autocorrelation
HV3	1.07	0.91	Inconclusive	No negative autocorrelation
HV4	0.69	1.05	Evidence for positive autocorrelation	No negative autocorrelation
HV5	1.25	0.91	Inconclusive	No negative autocorrelation
HV6	1.26	1.05	Inconclusive	No negative autocorrelation
HV7	1.39	0.91	Inconclusive	No negative autocorrelation
HV8	0.80	1.05	Evidence for positive autocorrelation	No negative autocorrelation
HV9	1.06	0.91	Inconclusive	No negative autocorrelation

As shown in Table 5.1 above, the Durbin-Watson tests for autocorrelation at the 0.05 level find that:

- none of the residential GP models conclusively suffer from autocorrelation;
- three of the models considered for the non-residential LV market suffer from positive autocorrelation, namely models LV5, LV9 and LV10; and
- three of the models considered for the non-residential HV market suffer from positive autocorrelation, namely models HV1, HV4 and HV8.

The AER states its view that it is not appropriate to use R^2 values and t-statistics as the basis for selecting models when autocorrelation is present.[693] In response to the draft decision, ActewAGL Distribution addressed the autocorrelation problem in the six models identified in the table above (LV5, LV9, LV10, HV1, HV4 and HV8) by amending them to include lagged consumption as an explanatory variable. ActewAGL Distribution also developed alternative versions of these models that excluded economic variables that became insignificant when the lag was introduced. ActewAGL Distribution applied the objective model selection process used to derive the forecast for ActewAGL Distribution's regulatory proposal for the subsequent regulatory period to the full set of candidate models, including the amended and alternative models created to address autocorrelation, and found that the models ActewAGL Distribution proposed in its regulatory proposal remain the preferred models. The Durbin-Watson tests and revised regression results are provided at Attachment H1.

Accordingly, no amendments are required to the consumption forecast models in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period.

In contrast, the AER's alternative forecast is invalid, since the LV model used by the AER (LV9)[694] suffers from positive autocorrelation (as shown in Table 5.1).

5.4.4.3 *The AER's view that ActewAGL Distribution's preferred models do not include price as an explanatory variable*

The AER states its view that ActewAGL Distribution fails to adopt the common practice of accounting for price either directly in the regression model or as a post-model adjustment. The

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[693] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-92

[694] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-91

AER provides one reference as an example as evidence for its view.[695] The single report cited by the AER as an example to support its view is insufficient evidence to found such a conclusion. Further, model specification should be an objective process and candidate models should not be omitted from this process purely on the basis of *a priori* preference.

Table 5.2 compares measures of model quality for ActewAGL Distribution's regulatory proposal for the subsequent regulatory period and the AER's draft decision. The table shows that the models chosen by the AER in order to include a price variable lose significant ability to minimise information loss, implying lower predictive capability. It is for this reason that ActewAGL Distribution's preferred models do not include price as an explanatory variable. Accordingly, the AER's criticism is unjustified.

Table 5.2: Consumption forecast model fit

Model type	*Model choice*	*Model*	*R^2*	*Relative likelihood to first feasible model with minimum AICC*
Residential GP	Regulatory proposal	R11	60%	100%
	AER preference chosen to include a price variable	R17	54%	37%
LV	Regulatory proposal	LV6	99%	100%
	AER preference chosen to include a price variable	LV9	96%	0.01%
HV	Regulatory proposal	HV6	95%	100%
	AER preference chosen to include a price variable	HV9	90%	1%

Source: Jacobs' analysis. Relative likelihood refers to the probability that a chosen model will minimize information loss in the dataset relative to a model with the minimum AIC value, calculated using the function $exp((AIC_{min}\text{-}AIC_i)/2)$

[695] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, page 6-90

The AER also states its concern that the potential effect of gas price and trends in fuel switching from entirely electricity-based consumption to electricity and gas-based consumption are not considered, particularly in light of expectations of gas price increases.[696] ActewAGL Distribution notes that there would need to be some certainty over future gas price changes in order to obtain meaningful results from modelling these considerations. Jacobs notes that any modelling including gas prices would be much more complex because it would also require concurrent consideration of change to gas usage to enable sense checking of the resulting elasticity estimates. The inclusion of gas variables would also substantially reduce the number of degrees of freedom available for testing the robustness of the model.[697]

The approach undertaken to select models for the development of ActewAGL Distribution's consumption forecasts is robust, appropriate and objective. It used an objective model selection process based on the AIC to develop parsimonious yet robust models. The AIC is a measure of the relative quality of a statistical model for a given set of data. It describes a trade-off between the goodness of fit of the model and the complexity of the model and it is generally regarded as the most widely known and used model selection tool.[698]

Given ActewAGL Distribution's acceptance that for small data sets, such as the annual consumption data used in its forecasting models, it may be more appropriate to use the Akaike Information Criterion with Correction (AICC),[699] Jacobs also reviewed the model selection

[696] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, pages 6-90 to 6-91

[697] See Attachment E3, Jacobs, 2015, *Response to AER on its draft determination on ACT energy forecasts, ActewAGL*, January, page 13

[698] AIC is based on information theory, and is calculated as follows:

$$AIC = 2K - 2log(L)$$

where K is the number of predictors and L is the likelihood statistic, where the $2K$ part of the formula is similar to a penalty for including extra predictors in the model, and the $-2log(L)$ part represents goodness of fit. The likelihood function reflects the conformity of the model to the observed data, so a more complex model will be reflected by a greater value of L. The optimal model is identified as that with the lowest AIC.

[699] AICC is the same as the AIC with a correction for finite sample sizes:

$$\mathrm{AICC} = AIC + \frac{2k(k+1)}{n-k-1}$$

process with the AICC statistic, rather than the AIC statistic, and found that the model selection outcomes were unchanged.[700]

Furthermore, the approach used to develop ActewAGL Distribution's consumption forecasts was comprehensive, as the original forecasting exercise examined a large set of model structures for each market, taking into account zero efficiency/gross energy considerations, total consumption/consumption per customer/consumption per person variations, and variations based on set of independent variables considered and transformations on those independent variables including taking logarithms. At least 182 models were considered by Jacobs for the residential sector, and at least 28 models were reviewed for the LV sector.[701]

Based on the information available to ActewAGL Distribution, the AER, in contrast, does not appear to have undertaken an objective approach to model selection. In both the residential and LV markets, the model selected by the AER yields the highest consumption forecast. These models have been selected without regard to statistical indicators of model quality. In particular, the AER has specified a preference for models that include price predictor variables, even though the objective model selection process undertaken by Jacobs for ActewAGL Distribution shows these variables detract from the information quality of the model (see Table 5.2 above).[702]

5.4.4.4 *The AER's view that ActewAGL Distribution's specification of the dependent variables in its preferred models are not in 'per customer' terms*

ActewAGL Distribution disagrees with the AER's view that "it is standard procedure to conduct consumption forecasts on the basis of consumption per customer" rather than on the basis of consumption per person.[703] The single study cited by the AER as an example to support its view is insufficient evidence to found such a conclusion. Further, as discussed above in the

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where n denotes the sample size and k denotes the number of explanatory variables. The AICC is therefore equivalent to the AIC with a greater penalty for extra parameters. AICC converges to AIC as n gets large. The formulation provided holds when the model is linear with normally distributed errors.

[700] See Attachment E3, Jacobs, 2015, *Response to AER on its draft determination on ACT energy forecasts, ActewAGL*, January, page 9

[701] See Attachment E3, Jacobs, 2015, *Response to AER on its draft determination on ACT energy forecasts, ActewAGL*, January, page 8

[702] See Attachment E3, Jacobs, 2015, *Response to AER on its draft determination on ACT energy forecasts, ActewAGL*, January, page 8

[703] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, pages 6-90

immediately preceding section, model specification should be an objective process and candidate models should not be omitted from this process purely on the basis of *a priori* preference.

In relation to the residential sector, ActewAGL Distribution rejects the AER's statement that "[c]hanges in population will not necessarily translate into increased customers if, for example, population change is driven by births as it does not result in new households."[704] Trends in persons per household have remained very static in the Canberra statistical area in recent years, with recorded household size statistics of 2.6 persons per household for the 2001, 2006 and 2011 censuses undertaken by the Australian Bureau of Statistics (see Attachment H19). The AER has not provided a basis for expecting this static trend will vary significantly in the future.

In relation to the LV sector, the AER states

> *[LV customer numbers] is not a linear series. Between 2003 and 2004, commercial LV customer numbers fell by 4.7 per cent, from 13,403 to 12,797. Therefore, without validation, it may not be reasonable to assume that historical trends will continue.*[705]

The AER's statement shows that there is uncertainty in the LV numbers. This is precisely the reason that Jacobs decided not to model LV customer numbers.[706] Non-linearities in customer numbers are a common feature of commercial Meter Installation Registration Number (MIRN) data. They often relate to customers being switched from commercial to residential status, which has large proportionate impacts on commercial numbers but not on residential, or some other data definitional change. Jacobs has advised that in these circumstances it is preferable to relate total energy directly to economic variables rather than to work with compromised data or, to avoid data problems, to work with shorter data series. Jacobs concludes that this approach results in more robust forecasts.[707]

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[704] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, pages 6-90

[705] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, pages 6-91

[706] See Attachment E3, Jacobs, 2015, *Response to AER on its draft determination on ACT energy forecasts, ActewAGL*, January, page 10

[707] See Attachment E3, Jacobs, 2015, *Response to AER on its draft determination on ACT energy forecasts, ActewAGL*, January, page 10

In summary, the AER's preference that dependent variables be defined in 'per customer' terms is not justified. Accordingly, no amendments are required to the consumption forecast models in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period.

5.4.4.5 *The AER's view that ActewAGL Distribution did not consider the drivers of customer forecasts in sufficient detail*

The AER states that ActewAGL Distribution should investigate the following when developing its customer number forecasts:

- whether the assumption that growth in customer numbers will mimic the moderation in population growth is too simplistic;
- whether customer number projections should be disaggregated by new connections, existing connections and disconnections; and
- whether the assumption that the historical trend in customers switching from entirely electricity based consumption to electricity and gas based consumption will continue is incorrect.

Each of the above comments is addressed in turn below. ActewAGL Distribution contends that each of the AER's concerns is unjustified.

It is reasonable to assume that customer numbers will grow at the same rate as population. As discussed in section 5.4.4.4, the number of persons per household has remained static in the ACT between 2001 and 2011. The AER notes that customer growth between 2009 and 2013 was 0.5 percentage points higher than the growth between 2000 and 2013.[708] However, similarly, population growth in the ACT between 2009 and 2013 was 0.4 percentage points per annum higher than growth between 2000 and 2013.[709]

Disaggregation of forecasts into new and existing connections and disconnections is not standard practice for studies providing annual projections. ActewAGL Distribution notes that the study cited by the AER as an example of what it claims to be standard procedure in relation to specification of the dependent variable did not disaggregate in this way.[710] In general, the

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[708] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, pages 6-91

[709] See Attachment E3, Jacobs, 2015, *Response to AER on its draft determination on ACT energy forecasts, ActewAGL*, January, page 12

[710] ACIL Tasman, 2012, Energy consumption forecasts 2011-12 to 2016-17, Energy consumption forecasts for Aurora Energy covering six customer classes, Prepared for Aurora Energy, April

number of connections and disconnections will be proportional to customer numbers on an annual basis, notwithstanding that seasonal patterns may affect monthly or quarterly estimates which are not required in this proposal.[711]

The AER also discusses trends in housing density, suggesting separation of new green-field estates from existing development which involves tearing down existing low or medium density development and replacing it with medium or high density development. Jacobs has advised that development of such a model would require a greater level of detail in energy consumption data than most distributors can presently access, as data collection processes are not geared around separately collecting data on new developments. Even if these data were available, it would be expected that:

- the trends towards increasing house size in separate dwellings may increase energy usage, and this is to some extent captured in the wealth parameter of the regression model; and
- the trends towards higher density development will reduce energy usage, acknowledging that central facilities such as lifts, laundry, foyers and shared outdoor facilities may compensate for some of the reduction.[712]

The AER notes that "*the customer numbers time series ActewAGL used to derive its consumption forecasts differs from the time series it provided in the economic benchmarking RINs*."[713] ActewAGL Distribution notes that customer numbers were not utilised in its proposed forecast, but can confirm that the differences referred to by the AER are due to the following two factors. The RIN numbers include customers in the disconnected and 'not specified' classes, whereas the numbers used by Jacobs do not. The RIN numbers are the average of end-of-year counts, whereas the numbers used by Jacobs are averages of the 12 months of the year.

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[711] Exceptions may occur in developing countries where there may be significant economic, social or demographic change in a short period of time. However, that is not relevant to the draft decision. See Attachment E3, Jacobs, 2015, *Response to AER on its draft determination on ACT energy forecasts, ActewAGL*, January, page 12

[712] See Attachment E3, Jacobs, 2015, *Response to AER on its draft determination on ACT energy forecasts, ActewAGL*, January, page 12

[713] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, pages 6-91

5.4.4.6 *The AER's view that ActewAGL Distribution should conduct tests to ensure no double counting of energy efficiency schemes*

The energy efficiency policies considered in Jacobs' projections include the Energy Efficiency Incentive Scheme (EEIS) implemented by the ACT government and Mandatory Energy Performance Standards (MEPS) implemented by the federal government.[714]

The AER notes that there is potential for double counting and scheme interactions when adjusting consumption forecasts for energy efficiency policies at the state and national level. However, based on a Jacobs' review[715] of the EEIS in August 2014, Jacobs considered it likely that zero or negligible[716] interactions will exist between the EEIS and MEPS. This is the case because it is the intention of the EEIS to include only energy savings above mandatory standards (if this is not the case the energy savings are not considered to be additional to what would occur without the policy in place). This occurs through the program calculating lifetime equipment emissions savings using energy use estimates from high efficiency equipment against current equipment performance standards.

The AER also notes that the AEMO report indicating the level of efficiency savings was written prior to the removal of the CPRS.[717] However, the EEIS efficiency savings are based on targets which are a percentage of projected energy use; therefore these energy savings should be provided with or without a CPRS in place. Energy savings based on efficiency standards (MEPS), should be undertaken irrespective of electricity price levels because they are mandated – customers replacing appliances can only purchase new appliances that are more efficient than their old ones.

ActewAGL Distribution therefore confirms that its energy efficiency projections do not include any double counting. Jacobs advised that undertaking sensitivity analysis (as suggested by the

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[714] See Attachment E3, Jacobs, 2015, *Response to AER on its draft determination on ACT energy forecasts, ActewAGL*, January, page 15

[715] Jacobs' review of the EEIS supplied to the ACT government, supplied as Attachment E4, Jacobs, 2014, *Energy Efficiency Improvement Scheme Review, ACT Government, EEIS Review: Final Report,* August

[716] While it is expected that zero interactions are likely, there may be some low level of interaction as EEIS administrators may not adjust emissions factors in time with introduction of new standards, leading to a lagged effect.

[717] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, pages 6-92.

AER[718]) of the potential impact of hypothetical double counting would not inform the proposed forecast.[719]

5.4.4.7 *Consumption observed in 2013-14*

In addition to addressing the AER's concerns, ActewAGL Distribution has also used the actual 2013-14 weather-corrected consumption, which has been observed since its regulatory proposal, to compare the accuracy of the forecasts for 2013-14 contained in its regulatory proposal and in the AER's draft decision. Figure 5.2 shows that the 2013-14 weather-corrected actual consumption is considerably closer to ActewAGL Distribution's forecast than to the AER's alternative forecast. The figure also shows that ActewAGL Distribution's in-sample model predictions fit historical weather-corrected actual consumption much better than the in-sample predictions from the AER's chosen models. In particular, the AER's chosen models over-predict consumption for each of the last four years.

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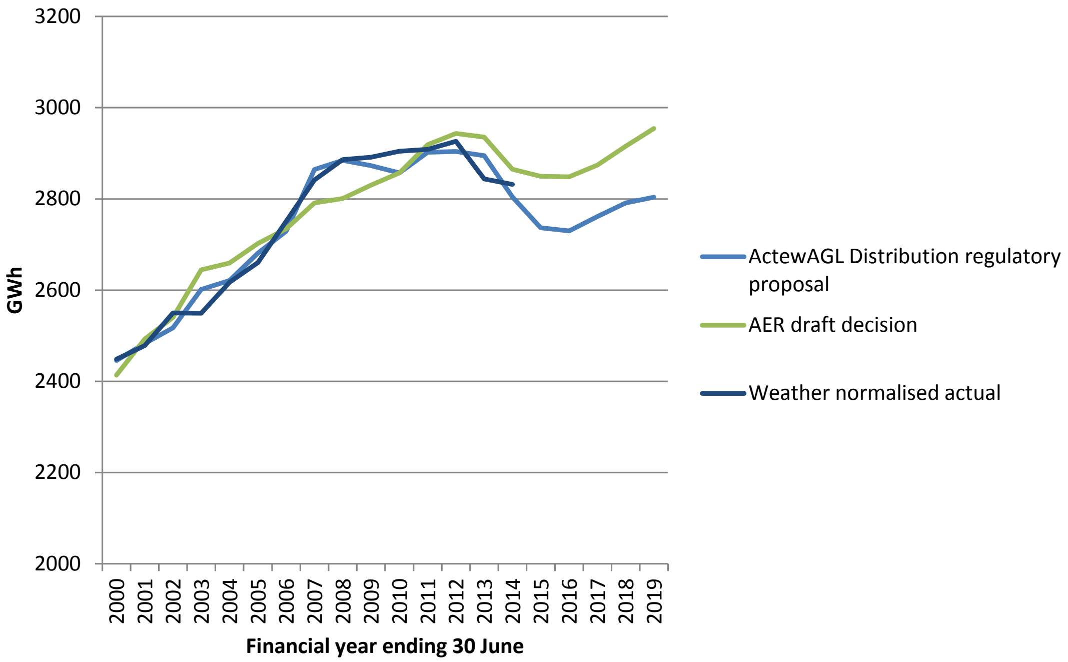
[718] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure (Appendix C)*, November, pages 6-91.

[719] See Attachment E3, Jacobs, 2015, *Response to AER on its draft determination on ACT energy forecasts, ActewAGL*, January, page 15

Figure 5.2: ActewAGL Distribution and AER forecasts and weather-normalised actual consumption



5.4.5 ActewAGL Distribution's revised regulatory proposal

ActewAGL Distribution maintains its forecast methods as proposed in its regulatory proposal for the subsequent regulatory period.

The AER's adjustments to ActewAGL Distribution's consumption forecasts are flawed for the reasons set out above. Further, in contrast to ActewAGL Distribution's approach, the AER's approach is not supported by any independent expert analysis.

ActewAGL Distribution has revised its forecast to account for recent observations and latest available forecasts of growth in the relevant economic and demographic explanatory variables.

Table 5.2: BIS Shrapnel forecast growth in economic and demographic variables (per cent)

Year	Employment	Resident population	Real state final demand	Cash rate (as at June)
2013-14*	0.57	1.29	1.93	2.50
2014-15	-0.51	1.22	0.63	2.50
2015-16	0.63	1.08	1.43	2.75
2016-17	2.72	1.16	3.76	3.25
2017-18	2.65	1.27	3.80	2.75
2018-19	1.92	1.28	2.82	3.00

* Resident population is an estimate for 2013-14. All other variables are actuals.

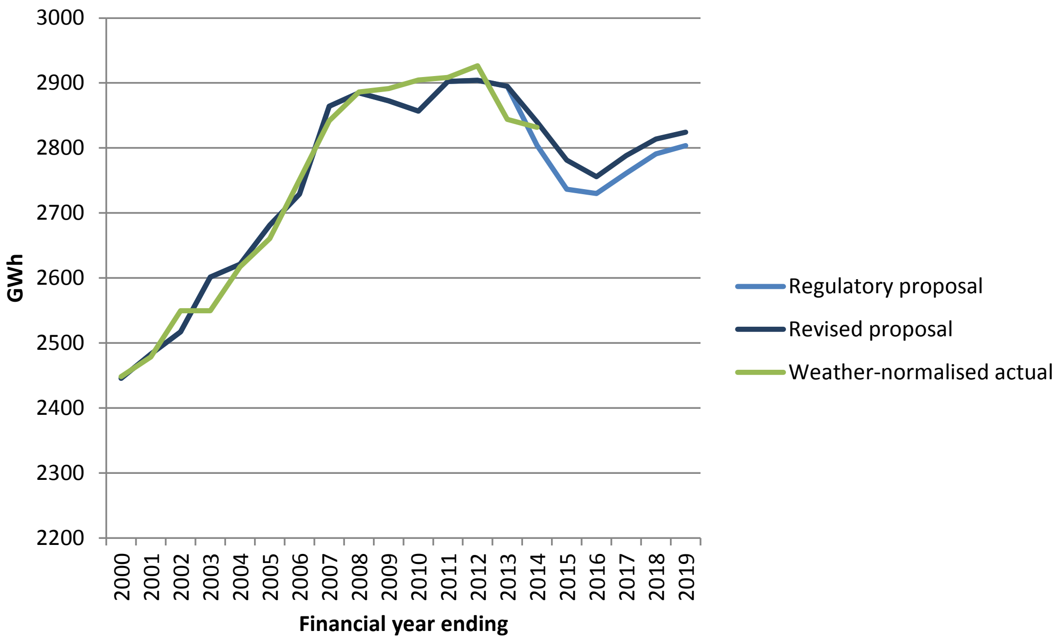
The revised forecast proposal is set out in Table 5.3 and the supporting calculations are set out in Attachment H17.

Table 5.3: Revised consumption forecast proposal

Year	2015-16	2016-17	2017-18	2018-19
GWh	2755.9	2788.2	2813.6	2824.1

Figure 5.3 illustrates that the forecast is increased relative to ActewAGL Distribution's regulatory proposal for the subsequent regulatory period by 1 per cent. This increase is due to increases in the forecast levels of population, employment and interest rates.

Figure 5.3: Revised consumption forecast proposal

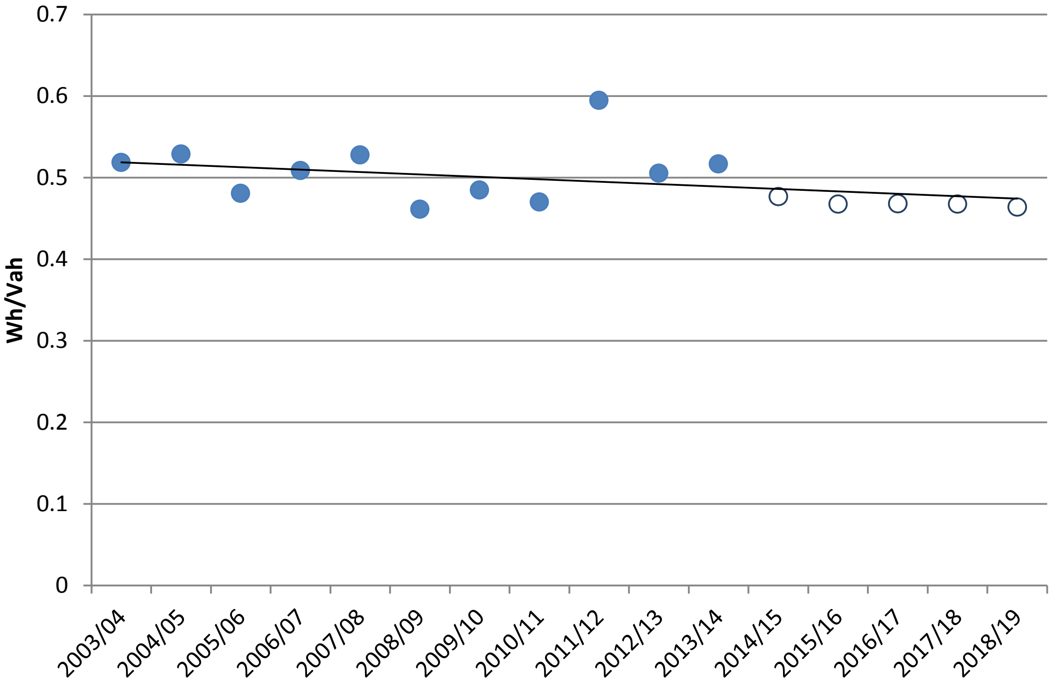


5.5 *Consistency between peak demand and consumption forecasts*

Figure 5.4 shows the actual system annual average load factor for 2004 to 2014 and forecasts for the 2014-2019 period based on the revised forecasts for system summer maximum demand and energy sales forecasts discussed above in Section 5.3.4 and Section 5.4.5.[720] This Figure is the updated version of Figure 5.4 in ActewAGL Distribution's Regulatory Proposal for the subsequent regulatory period. It shows that the forecast levels of the ratio of the revised demand and consumption forecasts are consistent with the historical trend.

[720] For further explanation of Figure 5.4, see ActewAGL, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period, Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), pages 110 and 111

Figure 5.4: System annual average load factor—actual and forecast



6 Regulatory asset base and depreciation

6.1 Introduction

This Chapter 6 responds to the AER's draft decision in respect of the RAB set out in Attachment 2 and depreciation as set out in Attachment 5 to its draft decision and its draft decision in respect of regulatory depreciation set out in Attachment 5 to that draft decision.

ActewAGL Distribution's response to the AER's draft decision on the RAB is set out in section 6.2 below and its response to the draft decision on regulatory depreciation is set out in section 6.3 below. Those responses are briefly summarised in turn below.

6.1.1 Regulatory asset base

In the draft decision, the AER:

- makes relatively modest reductions to ActewAGL Distribution's proposed opening RAB values as at 1 July 2014 for its distribution and transmission standard control assets (from $696.1 million ($ nominal) and $154.2 million ($ nominal) respectively to $695.6 million ($ nominal) and $154.1 million ($ nominal) respectively) as a consequence of its draft decision to use a remaining asset life of the opening asset class for both the distribution and transmission RABs of 20.42 years, instead of the value of 20.48 years proposed by ActewAGL Distribution, in rolling forward the RAB values for distribution and transmission in the 2009-14 regulatory control period;
- reduces ActewAGL Distribution's proposed closing RAB values as at 30 June 2019 for ActewAGL Distribution's transmission and distribution networks from $850.2 million ($ nominal) and $234.1 million ($ nominal) respectively to $751.6 million ($ nominal) and $184.2 million ($ nominal) respectively (or by 11.6% and 21.3% respectively) primarily as a consequence of its draft decision to reduce ActewAGL Distribution's proposed forecast capex and forecast regulatory depreciation for the 2014-19 period;
- makes consequential adjustments to the depreciations due to its draft decision capex program; and
- accepts ActewAGL Distribution's proposal that depreciation be calculated using forecast capex in establishing the opening RAB for the next regulatory control period (commencing on 1 July 2019).

With respect to the opening RAB values as at 1 July 2014 for its distribution and transmission standard control assets, ActewAGL Distribution accepts the AER's draft decision to reduce the remaining asset life of the opening asset class from 20.48 years to 20.42 years. ActewAGL Distribution also updates its proposed opening RAB values for 2014-19 to reflect finalised financial information on capex incurred in 2013/14 that has become available since its regulatory proposal for the regulatory proposal for the subsequent regulatory period was prepared. As a consequence, ActewAGL Distribution revises its proposed opening RAB values as at 1 July 2014 for distribution and transmission to $693.5 million ($ nominal) and $154 million ($ nominal) respectively. This is discussed further in Section 6.2.4 below.

ActewAGL Distribution rejects the AER's draft decision on its closing RAB values as at 30 June 2019 for each of distribution and transmission. ActewAGL Distribution does not accept the AER's draft decisions on forecast capex or forecast depreciation for the 2014-19 period. Accordingly, it proposes revised closing RAB values for 2014-19 for distribution and transmission that reflect its revised proposal on forecast net capex and forecast depreciation for that period of $341.4 million ($ nominal) and $180.5 million ($ nominal) respectively. This is discussed further in Section 6.2.4.

6.1.2 Regulatory depreciation

In its draft decision, the AER broadly accepts ActewAGL Distribution's proposed method for the calculation of regulatory depreciation allowances for the 2014-19 period. Nonetheless, the AER does not accept ActewAGL Distribution's proposed regulatory depreciation allowances of $154.1 million and $25.9 million ($ nominal) for the 2014-19 period for its distribution and transmission networks respectively, instead determining regulatory depreciation allowances of $151.8 million ($ nominal) and $25.2 million ($ nominal) respectively. The AER's decision to reject ActewAGL Distribution's proposed regulatory depreciation allowances and instead determine its own substitute allowances is the result of its draft decisions on various other components of ActewAGL Disribution's regulatory proposal for the regulatory proposal for the subsequent regulatory period which affect the forecast regulatory depreciation allowance.

While ActewAGL Distribution is content that the AER broadly accepts ActewAGL Distribution's method for the calculation of regulatory depreciation allowances for the 2014-19 period, it nonetheless rejects the AER's draft decision on the amount of those regulatory depreciation allowances. This is because ActewAGL Distribution does not accept the AER's draft decisions on other components of its regulatory proposal which affect the forecast regulatory depreciation allowance.

ActewAGL Distribution's revised proposed regulatory depreciation allowances for each regulatory year of the 2014-19 period for its distribution and transmission networks, calculated on the basis of ActewAGL Distribution's revised proposals for these other components in this revised regulatory proposal, are set out in Section 6.3.4 below.

6.2 Regulatory asset base

6.2.1 The relevant legal and regulatory framework for determining the RAB

Clause 6.12.1(6) and (18) of the Rules provides that the constituent decisions by the AER on which the distribution determination for ActewAGL Distribution for the regulatory proposal for the subsequent regulatory period is predicated include (amongst others):

- a decision on ActewAGL Distribution's RAB at the commencement of the regulatory control period in accordance with clause 6.5.1 and Schedule 6.2 of the Rules; and
- a decision on whether depreciation for establishing the RAB as at the commencement of the following regulatory control period is to be based on actual or forecast capex.

Clause 6.4.3 of the Rules provides for the annual revenue requirement for ActewAGL Distribution for each regulatory year of a regulatory control period to be determined using a building block approach, under which the opening RAB value at the beginning of the relevant regulatory year is used in the determination of the following constituent building blocks of the annual revenue requirement for that regulatory year:

- the indexation of the RAB (clause 6.4.1(a)(1) of the Rules);
- a return on capital for that regulatory year (clause 6.4.3(a)(2)); and
- the depreciation for that regulatory year (clause 6.4.3(a)(3)).

Clause 11.56.4(c) of the Rules provides that, for the purposes of making the distribution determination for ActewAGL Distribution for the the subsequent regulatory period, the AER must determine the opening value of the RAB for ActewAGL Distribution's distribution system in accordance with current Chapter 6 and as if the subsequent regulatory period comprised the transitional regulatory period (as the first regulatory year of the subsequent regulatory period) and all of the regulatory years of the subsequent regulatory period (as the remaining regulatory years of the subsequent regulatory period), and the transitional regulatory period were not a separate regulatory control period. That clause further states, for the avoidance of doubt, that it requires the AER to determine a notional opening value of the RAB for the regulatory year that comprises the transitional regulatory period.

Clause 6.5.1(e)(3) requires that, pursuant to the AER's roll forward model (RFM), the roll forward of the RAB from one regulatory control period to the beginning of the first regulatory year of a subsequent regulatory control period is to entail the value of the first mentioned RAB being adjusted for actual inflation, consistently with the method used for the indexation of the control mechanism(s) for standard control services during the first-mentioned regulatory control period.

Schedule 6.2 contains detailed provisions with respect to the establishment of the opening RAB for a regulatory control period and the roll forward of the RAB within the same regulatory control period.

Clause S6.2.2A of the Rules, in particular, provides for the AER to determine that the amount of capex that would otherwise be added to the previous value of the RAB in establishing the opening RAB for a regulatory control period should be reduced where certain requirements, referred to as the 'overspending requirement', the 'margin requirement' and the 'capitalisation requirement', are satisfied. Clause 11.56.5 of the Rules provides, however, that capex incurred in the transitional regulatory period or any preceding regulatory year is to be disregarded in applying the 'overspending requirement' and capex incurred in the regulatory year in which the first Capital Expenditure Incentive Guidelines were published and any preceding regulatory year is to be disregarded in applying the 'margin requirement' and the 'capitalisation requirement'.

Clause 11.56.4(f) provides that, for the purposes of the application of clauses 6.5.1(e)(1) and (3) and S6.2.1 in respect of the distribution determination for ActewAGL Distribution for the regulatory control period that follows the subsequent regulatory period, the transitional regulatory period must be treated as if it were the first regulatory year of the subsequent regulatory period, and not a separate regulatory control period.

6.2.2 ActewAGL Distribution’s proposal

RABs for 2009-14 regulatory control period

As part of ActewAGL Distribution’s proposal and in response to the AER’s Framework and Approach Stage 1, ActewAGL Distribution separated its dual function assets from other assets and rolled two RAB values forward in the 2009-14 regulatory control period in order to determine two starting RAB values as at 1 July 2014, one for transmission and one for distribution.[721]

ActewAGL Distribution used the AER’s RFM to derive starting RAB values as at 1 July 2014 for its distribution and transmission standard control assets of $696.1 million and $154.2 million

[721] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 245-246

respectively as shown in Table 6.1 and Table 6.2 below.[722] In so doing, ActewAGL Distribution used on opening remaining asset life for 2008/09 of 20.48 years.[723]

Table 6.1 Roll forward of the distribution RAB 2009–14, ActewAGL Distribution proposal

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Opening RAB	523.3	559.6	603.8	641.1	662.4
plus net capex	53.5	57.5	49.2	45.0	66.6
less regulatory depreciation	17.1	13.4	11.8	23.8	22.3
Closing RAB	559.6	603.8	641.1	662.4	706.7
Adjustment to opening value					-10.6
Opening RAB 1 July 2014					696.1

Table 6.2 Roll forward of the transmission RAB 2009–14, ActewAGL Distribution proposal

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Opening RAB	75.4	86.0	99.2	117.4	136.3
plus net capex	13.1	15.1	19.9	22.7	20.8
less regulatory depreciation	2.5	1.9	1.7	3.7	3.4
Closing RAB	86.0	99.2	117.4	136.3	153.8
Adjustment to opening value					0.4
Opening RAB 1 July 2014					154.2

[722] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 246-247

[723] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 247

RABs for 2014-19 period

In rolling forward the RABs for the 2014-19 period for the purposes of its regulatory proposal for the subsequent regulatory period, ActewAGL Distribution adopted its opening RAB values as at 1 July 2014 proposed in that regulatory proposal, added forecast capex and deducted forecast depreciation for that period as proposed in that regulatory proposal, and indexed the annual closing RAB with forecast inflation.[724] ActewAGL Distribution did not forecast any disposals.

For the purposes of calculating forecast depreciation, ActewAGL Distribution applied the standard asset lives applied in the 2009-14 regulatory control period but updated its calculation of asset remaining lives by adopting an approach based on real depreciation.[725]

Table 6.3 and Table 6.4 below set out ActewAGL Distribution's proposed RAB roll forward for the 2014-19 period for distribution and transmission respectively. ActewAGL Distribution's proposal contained forecast closing RABs as 30 June 2019 of $850.2 million and $234.1 million ($ nominal) for its distribution and transmission networks respectively.[726]

Table 6.3. Roll forward of the distribution RAB 2014-19, ActewAGL Distribution proposal

$ million (nominal)	2014/15	2015/16	2016/17	2017/18	2018/19
Opening RAB	696.1	737.6	765.1	792.7	818.9
Capex	68.5	58.1	58.8	58.8	64.0
Inflation indexation on RAB	17.6	18.6	19.3	20.0	20.7
less straight-line depreciation	44.6	49.2	50.5	52.6	53.4
Closing RAB	737.6	765.1	792.7	818.9	850.2

[724] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 248

[725] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 248-249

[726] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 249-250

Table 6.4. Roll forward of the transmission RAB 2014-19, ActewAGL Distribution proposal

$ million (nominal)	2014/15	2015/16	2016/17	2017/18	2018/19
Opening RAB	154.2	161.7	174.8	206.1	226.6
Capex	11.8	18.1	36.5	26.0	13.4
Inflation indexation on RAB	3.9	4.1	4.4	5.2	5.7
less straight-line depreciation	8.1	9.6	8.6	10.8	11.5
Closing RAB	161.7	174.8	206.1	226.6	234.1

Depreciation approach in RAB roll forward for next reset

Consistent with the AER's decision in respect of its new Capital Efficiency Sharing Scheme (CESS),[727] ActewAGL Distribution proposed that a depreciation schedule that has been calculated using forecast capex be adopted in establishing the opening RABs for the next regulatory control period (commencing on 1 July 2019).[728]

6.2.3 AER draft decision

RABs for 2009-14 regulatory control period

The AER did not accept ActewAGL Distribution's proposed opening RAB as at 1 July 2014 of $696.1 million and $154.2 million ($nominal) for the distribution and transmission networks respectively and instead determined opening RAB values as at 1 July 2014 of $695.6 million and $154.1 million ($nominal) respectively as shown in Table 6.5 and Table 6.6 below.[729]

The basis for the difference between the AER's draft decision and ActewAGL Distribution's proposal for the opening RABs as at 1 July 2014 was an adjustment to the remaining asset life of

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[727] AER 2013, Better Regulation, Explanatory Statement, Capital Expenditure Incentive Guideline, November 2013, p. 63

[728] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 249

[729] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 2*, pp. 2-7 to 2-8 and 2-15 to 2-16

the opening asset class for both the distribution and transmission RABs from 20.48 to 20.42 years.[730]

Table 6.5. Roll Forward of the distribution RAB 2009–14, AER draft decision

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Opening RAB	523.3	559.6	603.6	640.9	662.0
Capital expenditure	53.5	57.5	49.2	45.0	66.6
Inflation indexation on opening RAB	9.5	15.9	20.5	11.3	16.2
less straight-line depreciation	26.7	29.4	32.4	35.2	38.6
Closing RAB	559.6	603.6	640.9	662.0	706.2
Difference between actual and estimated capex for 2008-09					-7.0
Return on difference for 2008-09 capex					-3.6
Opening RAB 1 July 2014					695.6

Table 6.6. Roll forward of the transmission RAB 2009–14, AER draft decision

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Opening RAB	75.4	86.0	99.2	117.4	136.3
Capital expenditure	13.1	15.1	19.9	22.7	20.8
Inflation indexation on opening RAB	1.4	2.4	3.4	2.1	3.3
less straight-line depreciation	3.9	4.4	5.0	5.8	6.8
Closing RAB	86.0	99.2	117.4	136.3	153.7
Difference between actual and estimated capex for 2008-09					0.2
Return on difference for 2008-09 capex					0.1
Opening RAB 1 July 2014					154.1

[730] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 2*, pp. 2-7 and 2-15 to 2-16

RABs for 2014-19 period

The AER determined forecast closing RABs as at 30 June 2019 of $751.6 million and $184.5 million ($ nominal) for ActewAGL Distribution's transmission and distribution networks respectively as set out in Table 6.7 and Table 6.8 below.[731] For distribution, this represents a decrease of $98.7 million ($ nominal) (or 11.6%) compared to ActewAGL Distribution's proposal and for transmission, a decrease of $49.9 million ($ nominal) (or 21.3%). These reductions are attributable to the AER's draft decision on the opening RAB values for distribution and transmission as at 1 July 2014 (discussed above), and on forecast capex and corresponding effect on forecast depreciation which are set out in Attachments 6, 5 and 4 respectively of the AER's draft decision. The capex program is discussed in detail in Chapter 4 of this revised regulatory proposal. The AER's draft decision in relation to rolling forward of the RAB for the 2014-19 period is shown in Table 6.7 and Table 6.8.

Table 6.7. Roll forward of the distribution RAB 2014-19, AER draft decision

$ million (nominal)	2014/15	2015/16	2016/17	2017/18	2018/19
Opening RAB	695.6	720.3	729.8	738.3	743.9
Capital expenditure	51.7	39.7	39.2	37.6	39.5
Inflation indexation on RAB	17.4	18.0	18.2	18.5	18.6
less straight-line depreciation	44.4	48.3	48.9	50.4	50.5
Closing RAB	720.3	729.8	738.3	743.9	751.6

Table 6.8. Roll forward of the transmission RAB 2014-19, AER draft decision

$ million (nominal)	2014/15	2015/16	2016/17	2017/18	2018/19
Opening RAB	154.1	159.2	164.6	176.8	183.8
Capital expenditure	9.3	10.4	17.3	12.4	5.9
Inflation indexation on RAB	3.9	4.0	4.1	4.4	4.6
less straight-line depreciation	8.1	8.9	9.2	9.9	10.2
Closing RAB	159.2	164.6	176.8	183.8	184.2

[731] AER, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 2*, November 2014, pp. 2-8 to 2-9 and 2-15 to 2-16

Depreciation approach in RAB roll forward for next reset

The AER accepted ActewAGL Distribution's proposal to use forecast depreciation to establish the opening RABs at the commencement of the 2019-24 regulatory control period.[732]

6.2.4 ActewAGL Distribution's response and revised proposal

RABs for 2009-14 regulatory control period

In the draft decision, the AER made an adjustment to the remaining life of the opening asset class for the 1 July 2009 opening RAB. ActewAGL Distribution accepts the AER's proposed remaining life value and has incorporated this in its revised proposal.

Table 6.9 and Table 6.10 set out ActewAGL Distribution's revised roll forward of the distribution and transmission RABs respectively. Since ActewAGL Distribution's regulatory proposal for the subsequent regulatory period was prepared, financial information on capex incurred in 2013/14 has been finalised and this updated information is reflected in the revised figures.

Consistent with the regulatory proposal for the subsequent regulatory period, ActewAGL Distribution has adjusted the opening RAB as at 1 July 2014 for the difference between forecast capex and actual capex incurred in 2008/09. In so doing, the difference between forecast capex and actual capex incurred has also been adjusted for a real return in accordance with the determined WACC of 8.79 per cent and actual inflation to account for the time value of money in accordance with the AER's RFM. At the end of 2013/14, the total adjustments due to the difference between actual and forecast capex including the time value of money in 2008/09 were -$10.2 million for distribution and transmission combined. The opening RAB as at 1 July 2014 has been reduced for these adjustments.

[732] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 2*, pp. 2-9 and 2-17

Table 6.9. Roll forward of the distribution RAB 2009–14, ActewAGL Distribution's revised proposal

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Opening RAB	523.3	559.6	603.6	640.9	662.0
plus net capex	53.5	57.5	49.2	45.0	64.5
less regulatory depreciation	-17.2	-13.5	-11.9	-23.9	-22.4
Closing RAB	559.6	603.6	640.9	662.0	704.1
Adjustment to opening value					-10.6
Opening RAB 1 July 2014					693.5

Table 6.10. Roll Forward of the transmission RAB 2009–14, ActewAGL Distribution's revised proposal

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Opening RAB	75.4	86.0	99.2	117.4	136.3
plus net capex	13.1	15.1	19.9	22.7	20.8
less regulatory depreciation	-2.5	-2.0	-1.7	-3.8	-3.4
Closing RAB	86.0	99.2	117.4	136.3	153.6
Adjustment to opening value					0.4
Opening RAB 1 July 2014					154.0

RABs for 2014-19 period

ActewAGL Distribution has used the opening RAB values as at 1 July 2014 from section 6.5.1 to roll forward the RAB for the 2014-19 period.

As discussed in detail in Chapter 4, ActewAGL Distribution does not accept the AER's draft decisions on forecast capex and forecast depreciation and consequently does not accept the depreciation included in the draft decision.

ActewAGL Distribution has rolled forward the RAB in the 2014-19 period using the AER's PTRM as set out in Table 6.11 and Table 6.12. This results in closing RAB values as at 30 June 2019 of $831.7 million ($ nominal) and $213.8 million ($ nominal) for distribution and transmission respectively. These figures incorporate ActewAGL Distribution's revised capex forecasts for the 2014-19 period set out in Chapter 4 of this revised regulatory proposal and applies the methodology to estimate the remaining asset lives that was accepted by the AER in its draft decision. It also uses the same standard lives as in the draft decision (proposed by ActewAGL Distribution) as the basis for calculating depreciation.

Table 6.11. Roll forward of the distribution RAB 2014–19, ActewAGL Distribution revised proposal

$ million (nominal)	2014/15	2015/16	2016/17	2017/18	2018/19
Opening RAB	693.5	734.0	758.5	782.8	803.9
Capex	67.3	55.2	55.5	53.9	60.8
Inflation indexation on RAB	17.3	18.4	19.0	19.6	20.1
less straight-line depreciation	44.1	49.0	50.2	52.4	53.1
Closing RAB	734.0	758.5	782.8	803.9	831.7

Table 6.12. Roll forward of the transmission RAB 2014–19, ActewAGL Distribution revised proposal

$ million (nominal)	2014/15	2015/16	2016/17	2017/18	2018/19
Opening RAB	154.0	161.6	169.2	188.1	207.0
Capex	11.8	12.6	24.2	24.5	12.7
Inflation indexation on RAB	3.9	4.0	4.2	4.7	5.2
less straight-line depreciation	8.0	9.0	9.5	10.4	11.1
Closing RAB	161.6	169.2	188.1	207.0	213.8

6.3 Regulatory depreciation

6.3.1 The relevant legal and regulatory framework for determining regulatory depreciation

Clause 6.12.1(8) of the Rules provides that one of the constituent decisions by the AER on which the distribution determination for ActewAGL Distribution for the subsequent regulatory period is predicated is a decision on whether or not to approve the depreciation schedules submitted by ActewAGL Distribution and, if the AER decides against approving them, a decision determining depreciation schedules in accordance with clause 6.5.5(b) of the Rules.

Clause 6.4.3 of the Rules provides for the ARR for ActewAGL Distribution for each regulatory year of a regulatory control period to be determined using a building block approach, under which one of the constituent building blocks is the depreciation for that regulatory year calculated in accordance with clause 6.5.5 of the Rules.

Clause 11.56.4(c) of the Rules provides that, for the purposes of making the distribution determination for ActewAGL Distribution for the subsequent regulatory period, the AER must determine the ARR for ActewAGL Distribution for each regulatory year of the subsequent regulatory period in accordance with current Chapter 6 and as if the subsequent regulatory period comprised the transitional regulatory period (as the first regulatory year of the subsequent regulatory period) and all of the regulatory years of the subsequent regulatory period (as the remaining regulatory years of the subsequent regulatory period), and the transitional regulatory period were not a separate regulatory control period. That clause further states, for the avoidance of doubt, that it requires the AER to determine a notional ARR for the regulatory year that comprises the transitional regulatory period.

Clause 6.5.5(a) of the Rules provides that the depreciation for each regulatory year must be calculated:

- on the value of the assets included in the RAB, as at the beginning of that regulatory year, for ActewAGL Distribution's distribution system; and
- provided those schedules conform with the requirements set out in clause 6.5.5(b) of the Rules, using depreciation schedules for each asset or category of assets that are nominated in ActewAGL Distribution's building block proposal and otherwise using the depreciation schedules determined by the AER.

It follows that the AER's constituent decision on depreciation under clause 6.12.1(8) of the Rules includes a decision on depreciation for the transitional regulatory period.

Clause 6.5.5(b) of the Rules provides that the relevant depreciation schedules must conform to the following requirements:

- the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets;
- the sum of the real value of the depreciation that is attributable to any asset or category of assets over the economic life of that asset or category must be equivalent to the value at which that asset or category was first included in the RAB for the relevant distribution system; and
- the economic life of the relevant assets and the depreciation methods and rates underpinning the calculation of depreciation for a given regulatory control period must be consistent with those determined for the same assets on a prospective basis in the distribution determination for the period.

6.3.2 ActewAGL Distribution's proposal

In its regulatory proposal for the subsequent regulatory period, ActewAGL Distribution proposed total forecast regulatory depreciation allowances of $154.1 million ($ nominal) and $25.9 million ($ nominal) for the 2014-19 period for its distribution and transmission networks respectively.[733] To calculate its depreciation allowances, ActewAGL Distribution proposed to use:[734]

- the straight-line method of depreciation employed in the AER's PTRM;
- the closing RAB as at 30 June 2014 derived from the AER's RFM;
- its proposed forecast capex for the 2014-19 period;
- standard asset lives for depreciating new assets associated with forecast capex for the 2014-19 period consistent with those approved for the purposes of ActewAGL Distribution's distribution determination for the 2009-14 regulatory control period; and
- proposed remaining asset lives in existence as at 30 June 2014 based on an approach that uses real depreciation.

6.3.3 AER draft decision

In its draft decision, the AER broadly accepts ActewAGL Distribution's proposed method for the calculation of regulatory depreciation allowances for the 2014-19 period. Specifically, the AER accepts ActewAGL Distribution's proposed:[735]

- asset classes, straight-line method and standard asset lives used to calculate the regulatory depreciation allowance; and
- method to estimate the remaining asset lives as at 1 July 2014 with some updates of the values due to some consequential updates to reflect the AER's adjustments to ActewAGL Distribution's opening RABs in the RFMs.

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[733] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 249-250, Tables 9.3 and 9.4

[734] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 248-249

[735] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 5*, p. 5-7

The AER accepts ActewAGL Distribution's proposed asset classes and standard asset lives as it considers them to be consistent with those approved in making ActewAGL Distribution's distribution determination for the 2009-14 regulatory control period.[736] The AER accepts ActewAGL Distribution's proposed remaining asset lives as at 1 July 2014 (subject to some consequential updates to reflect the AER's adjustments to ActewAGL Distribution's opening RABs in ActewAGL Distribution's proposed RFMs) for the purposes of making the distribution determination for ActewAGL Distribution for the subsequent regulatory period, notwithstanding that ActewAGL Distribution's proposed approach to calculating remaining asset lives differs from that of the AER and the AER expresses some concern with this, because the difference of approach has a negligible effect on ActewAGL Distribution's total revenue requirement for the 2014-19 period.[737]

Nonetheless, the AER does not accept ActewAGL Distribution's proposed regulatory depreciation allowances of $154.1 million and $25.9 million ($ nominal) for the 2014-19 period for its distribution and transmission networks respectively.[738] Instead, the AER determines regulatory depreciation allowances of $151.8 million ($ nominal), representing a reduction of 1.5 per cent, and $25.2 million ($ nominal), representing a reduction of 2.4 per cent, for its distribution and transmission networks respectively.

The AER's decision to reject ActewAGL Distribution's proposed regulatory depreciation allowances and instead determine its own substitute allowances is the result of its draft decisions on various other components of ActewAGL Distribution’s regulatory proposal for the subsequent regulatory period which affect the forecast regulatory depreciation allowance, in particular its draft decisions on forecast capex (discussed in Chapter 4 of this revised regulatory proposal) and the opening RAB value (discussed in section 6.2 of this Chapter 6 above).[739]

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[736] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 5*, pp. 5-7 and 5-11

[737] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 5*, pp. 5-11 to 5-12

[738] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 5*, pp. 5-7 and 5-11

[739] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 5*, pp. 5-7 and 5-11

6.3.4 ActewAGL Distribution’s response and revised proposal

While ActewAGL Distribution is content that the AER broadly accepts ActewAGL Distribution's method for the calculation of regulatory depreciation allowances for the 2014-19 period, it nonetheless rejects the AER's draft decision on the amount of those regulatory depreciation allowances. This is because ActewAGL Distribution does not accept the AER's draft decisions on other components of its regulatory proposal which affect the forecast regulatory depreciation allowance.

In particular, ActewAGL Distribution does not accept the AER's draft decision on forecast capex for the 2014-19 period for the reasons explained in Chapter 4 of this revised regulatory proposal or the AER's draft decision on ActewAGL Distribution's opening RAB values for the reasons discussed in section 6.2 of this Chapter 6 above. It follows that ActewAGL Distribution also does not accept the AER's updates to ActewAGL Distribution's proposed remaining asset lives as at 1 July 2014 to reflect the AER's adjustments to ActewAGL Distribution's opening RABs in ActewAGL Distribution's proposed RFMs.

ActewAGL Distribution's revised proposed regulatory depreciation allowances for each regulatory year of the 2014-19 period for its distribution and transmission networks, calculated on the basis of ActewAGL Distribution's revised proposals for forecast capex for the 2014-19 period set out in Chapter 4 and opening RAB values set out in section 6.2 above, are set out in Table 6.13.

Table 6.13 Regulatory depreciation allowances for 2014–19, ActewAGL Distribution revised proposal

$ million (nominal)	2014/15	2015/16	2016/17	2017/18	2018/19
Distribution network	26.8	30.7	31.2	32.8	33.0
Transmission network	4.2	5.0	5.3	5.7	5.9

7 Corporate income tax

7.1 Introduction

This Chapter responds to the AER's draft decision in respect of corporate income tax set out in Attachment 8 to its draft decision.

In the draft decision, the AER does not accept ActewAGL Distribution's proposed cost of corporate income tax allowances for the 2014-19 period. It instead determines corporate income tax allowances of $31.4 million and $4.4 million ($ nominal) for its distribution and transmission networks respectively. This represents reductions to ActewAGL Distribution's proposed nominal allowances of $22.3 million (or 41.5 per cent) and $4.5 million (or 50.3 per cent) respectively.[740]

The AER's reductions to ActewAGL Distribution's proposed corporate income tax allowances are attributable to the AER's draft decision not to accept the following of ActewAGL Distribution's proposed inputs to the calculation of those allowances:[741]

- the value of gamma;
- the standard tax asset life for the 2014-19 period for the 'equity raising costs' asset class; and
- other building block components including forecast opex and forecast capex which impact on required revenues and thus the estimate of the cost of corporate income tax.

In so deciding, the AER accepts ActewAGL Distribution's proposed:[742]

- opening tax asset bases (TABs) as at 1 July 2014 for its distribution and transmission networks;
- standard tax asset lives for the 2014-19 period with the exception only of that for the 'equity raising costs' asset class; and
- remaining tax asset lives for the period.

ActewAGL Distribution rejects the AER's draft decision on the cost of corporate income tax for the 2014-19 period. In particular, while ActewAGL Distribution accepts the AER's draft decision

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[740] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 8*, p. 8-11

[741] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 8*, p. 8-11

[742] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 8*, pp. 8-11 to 8-15

on the standard tax asset life for the 'equity raising costs' asset class for the 2014-19 period of 5 years, it does not accept the AER's draft decisions on the value of gamma, forecast opex for the 2014-19 period or forecast capex for that period.

ActewAGL Distribution maintains its initial proposed value for gamma of 0.25 for the reasons discussed in section 8.5 of this revised regulatory proposal, and proposes revised forecasts of opex and net capex for the 2014-19 period of $359.1million ($ nominal) and $341.4 million ($ nominal) respectively for the reasons discussed in Chapters 3 and 4 respectively. It has also updated the opening TABs as at 1 July 2014 for distribution and transmission to reflect finalised financial information on actual capex incurred during 2013/14 that has become available since its regulatory proposal for the subsequent regulatory period was prepared.

ActewAGL Distribution's resultant revised proposal for the forecast cost of corporate income tax for the 2014-19 period is set out in Table 7.1 below.

Table 7.1 Corporate income tax building block 2014–19, distribution and transmission

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Tax Payable, Distribution	- 11.5	- 12.2	- 11.8	- 13.8	- 14.2
Value of imputation credits	2.9	3.1	2.9	3.4	3.5
Tax allowance, Distribution	8.6	9.2	8.8	10.3	10.6
Tax Payable, Transmission	1.8	2.0	2.0	2.4	2.6
Value of imputation credits	- 0.5	- 0.5	- 0.5	- 0.6	- 0.6
Tax allowance, Transmission	1.4	1.5	1.5	1.8	1.9

7.2 The relevant legal and regulatory framework for corporate income tax

Clause 6.12.1(7) of the Rules provides that one of the constituent decisions by the AER on which the distribution determination for ActewAGL Distribution for the subsequent regulatory proposal is predicated is a decision on the estimated cost of corporate income tax to ActewAGL Distribution for each regulatory year of the regulatory control period in accordance with clause 6.5.3.

Clause 6.4.3 of the Rules provides for the annual revenue requirement for ActewAGL Distribution for each regulatory year of a regulatory control period to be determined using a building block approach, under which the constituent building blocks of the annual revenue requirement for a regulatory year include (amongst others) the estimated cost of corporate income tax of ActewAGL Distribution for that year determined in accordance with clause 6.5.3.

Clause 11.56.4(c) of the Rules provides that, for the purposes of making the distribution determination for ActewAGL Distribution for the subsequent regulatory period, the AER must determine the annual revenue requirement for ActewAGL Distribution for each regulatory year of the subsequent regulatory period and its total revenue requirement for the subsequent regulatory period in accordance with current Chapter 6 and as if the subsequent regulatory period comprised the transitional regulatory period (as the first regulatory year of the subsequent regulatory period) and all of the regulatory years of the subsequent regulatory period (as the remaining regulatory years of the subsequent regulatory period), and the transitional regulatory period were not a separate regulatory control period. That clause further states, for the avoidance of doubt, that it requires the AER to determine a notional annual revenue requirement for the regulatory year that comprises the transitional regulatory period.

Clause 6.5.3 of the Rules provides that the estimated cost of corporate income tax of ActewAGL Distribution for each regulatory year (ETC_t) must be estimated in accordance with the formula:$ETC_t = (ETI_t \times r_t)(1-\gamma)$

where:

- ETI_t is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of standard control services if such an entity, rather than ActewAGL Distribution, operated the business of ActewAGL Distribution, such estimate being determined in accordance with the PTRM;
- r_t is the expected statutory income tax rate for that regulatory year as determined by the AER; and
- γ is the value of imputation credits.

7.3 ActewAGL Distribution's proposal

7.3.1 Overview

In its regulatory proposal for the subsequent regulatory period, ActewAGL Distribution, using the PTRM, proposed corporate income tax allowances of $53.7 million and $9 million ($ nominal) for its distribution and transmission networks respectively. Specifically, ActewAGL Distribution proposed the corporate income tax allowances for the 2014-19 period for its distribution and transmission networks set out in Table 7.2 below.[743]

[743] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 301

Table 7.2 Corporate income tax building block 2014–19, distribution and transmission

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Tax Payable, Distribution	13.0	13.8	13.4	15.3	16.1
Value of imputation credits	-3.3	-3.5	-3.4	-3.8	-4.0
Tax allowance, Distribution	9.8	10.4	10.1	11.5	12.1
Tax Payable, Transmission	2.0	2.1	2.2	2.7	2.9
Value of imputation credits	-0.5	-0.5	-0.6	-0.7	-0.7
Tax allowance, Transmission	1.5	1.6	1.7	2.0	2.2

These corporate income tax allowances were calculated using:

- opening TABs as at 1 July 2014 of $609.1 million and $137.1 million ($ nominal) for its distribution and transmission networks respectively;[744]
- an expected statutory income tax rate of 30 per cent per year;[745]
- a value for gamma of 0.25;[746] and
- standard and remaining tax asset lives for assets in the TAB as at 1 July 2014.[747]

These assumptions were all part of the submitted PTRMs in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period.

[744] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 299

[745] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 298

[746] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 301

[747] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 300-301

The statutory tax rate is determined by the Government and is non-controversial. ActewAGL Distribution's proposal in respect of the value of gamma is discussed in section 8.5 of this revised regulatory proposal. ActewAGL Distribution's proposed opening TABs as at 1 July 2014, and its proposed standard and remaining tax asset lives, are discussed in sections 7.4.2 and 7.4.3 respectively below.

7.3.2 Opening TABs for 2014-19 period

In ActewAGL Distribution's proposal the TAB was rolled forward to 1 July 2014 using the AER's RFM, and the same capex and capital contributions inputs as the roll forward of the RAB.[748]

ActewAGL Distribution's TAB was apportioned into distribution and transmission on the same basis as the RAB.[749] The TAB was then rolled forward using capex in the 2009–14 period directly allocated between transmission and distribution. The same proportional allocation between transmission and distribution was applied for the TAB as for the RAB. Table 7.3 and Table 7.2 set out ActewAGL Distribution's proposed TAB roll forward for the 2009-14 regulatory control period for distribution and transmission respectively.

Table 7.3 Roll forward of the distribution TAB 2009–14, ActewAGL Distribution proposal

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Opening TAB	412.2	452.7	499.1	532.5	563.0
plus capex	58.0	66.0	55.2	54.2	72.7
less depreciation	17.5	19.6	21.8	23.7	26.6
Closing TAB	452.7	499.1	532.5	563.0	609.1

[748] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 299

[749] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 299

Table 7.2 Roll forward of the transmission TAB 2009–14, ActewAGL Distribution proposal

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Opening TAB	59.4	69.5	81.0	97.4	118.7
plus capex	12.6	14.4	19.8	25.2	23.2
less depreciation	2.5	2.9	3.4	3.9	4.8
Closing TAB	69.5	81.0	97.4	118.7	137.1

ActewAGL Distribution's resultant proposed opening TABs as at 1 July 2014 for distribution and transmission were, therefore, $609.1 million and $137.1 million ($ nominal) respectively.

7.3.3 Standard and remaining tax asset lives

ActewAGL Distribution calculated remaining tax asset lives for assets in the TABs as at 1 July 2014 using real depreciation in a similar manner to that applied to calculate the RAB remaining asset lives.[750] It proposed to apply the same standard tax asset lives for use in the 2014-19 period as were approved for the 2009-14 regulatory control period, except for the 'Opening distribution assets' asset class.

ActewAGL Distribution's proposed standard and remaining tax asset lives for the 2014-19 period for its distribution and transmission assets were set out in Table 11.5 of its regulatory proposal for the subsequent regulatory period and included in the RFMs for distribution and transmission.

Using these standard and remaining tax asset lives, ActewAGL Distribution rolled forward the TABs as at 1 July 2014 in accordance with the PTRM to determine the opening TABs for each regulatory year of the 2014-19 period as set out in Table 7.3 and Table 7.4.[751]

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[750] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 300-301

[751] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 299-300

Table 7.3 Roll Forward of the distribution TAB 2014–19, ActewAGL Distribution proposal

$ million (nominal)	2014/15	2015/16	2016/17	2017/18	2018/19
Opening TAB	609.1	652.5	682.3	710.1	740.1
plus capex	74.9	65.1	65.1	65.5	72.4
less depreciation	31.6	35.2	37.4	35.5	36.4
Closing TAB	652.5	682.3	710.1	740.1	776.0

Table 7.4 Roll forward of the transmission TAB 2014-19, ActewAGL Distribution proposal

$ million (nominal)	2014/15	2015/16	2016/17	2017/18	2018/19
Opening TAB	137.1	142.8	153.9	182.3	200.1
plus capex	11.5	17.6	35.5	25.3	13.1
less depreciation	5.8	6.5	7.1	7.5	8.1
Closing TAB	142.8	153.9	182.3	200.0	205.1

7.4 AER draft decision

7.4.1 Overview

In its draft decision, the AER did not accept ActewAGL Distribution's proposed cost of corporate income tax allowances for the 2014-19 period. It instead determines corporate income tax allowances of $31.4 million and $4.4 million ($ nominal) for its distribution and transmission networks respectively.[752] This represents a reduction of $22.3 million (or 41.5 per cent) and $4.5 million (or 50.3 per cent) ($ nominal) for its distribution and transmission networks respectively.

The AER's reductions to ActewAGL Distribution's proposed corporate income tax allowances are attributable to the AER's decision not to accept the following of ActewAGL Distribution's proposed inputs to the calculation of those allowances:[753]

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[752] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 8*, p. 8-11

[753] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 8*, p. 8-11

- the value of gamma;
- the standard tax asset life for the 2014-19 period for the 'equity raising costs' asset class; and
- other building block components including forecast opex and forecast capex which impact on required revenues and thus the estimate of the cost of corporate income tax.

The AER's draft decision to adopt a value of 0.4 for gamma is discussed in section 8.5 of this revised regulatory proposal, its draft decision on forecast opex is discussed in Chapter 3 and its draft decision on forecast capex is discussed in Chapter 4. Its draft decision on other inputs to the estimate of the cost of corporate income tax are discussed in sections 7.4.2 to 7.4.4.

7.4.2 Opening TABs for 2014-19 period

The AER accepted ActewAGL Distribution's proposed opening TABs as at 1 July 2014 of $609.1 million and $137.1 million ($ nominal) for its distribution and transmission networks respectively.[754]

7.4.3 Standard tax asset lives

The AER accepts the majority of ActewAGL Distribution's proposed standard tax asset lives for its distribution and transmission networks used in rolling forward the respective TABs from 1 July 2014 so as to calculate tax depreciation and which is one input into the cost of corporate income tax for each regulatory year of the 2014-19 period.[755]

However, the AER changes the standard tax life for the 'equity raising costs' asset class from ActewAGL Distribution's proposed 44.5 years to 5 years.[756] The AER states that this is because the Australian Taxation Office requires equity raising costs to be amortised over a five-year period on a straight-line basis.

This adjustment to standard asset lives, as well as the reduced capex program allowed in the draft decision means that the value of the TABs for distribution and transmission for the 2015/16 and subsequent regulatory years of the 2014-19 period, used to calculate tax depreciation and, thus, the cost of corporate income tax are likewise reduced. The AER's draft decision on the

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[754] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 8*, pp. 8-11 to 8-12

[755] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 8*, p. 8-13

[756] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 8*, pp. 8-13 to 8-14

opening and closing values of the distribution and transmission TABs for each year of the 2014-19 period is set out in Table 7.5 and Table 7.6.

Table 7.5 Roll forward of the distribution TAB 2014–19, AER draft decision

$ million (nominal)	2014/15	2015/16	2016/17	2017/18	2018/19
Opening TAB	609.1	636.6	649.6	660.0	671.5
plus capex	59.0	47.6	46.5	45.3	49.0
less depreciation	-31.6	-34.6	-36.1	-33.7	-34.1
Closing TAB	636.6	649.6	660.0	671.5	686.5

Table 7.6 Roll forward of the transmission TAB 2014–19, AER draft decision

$ million (nominal)	2014/15	2015/16	2016/17	2017/18	2018/19
Opening TAB	137.1	140.5	144.3	154.6	160.2
plus capex	9.2	10.2	17.0	12.3	5.9
less depreciation	-5.8	-6.4	-6.8	-6.7	-6.9
Closing TAB	140.5	144.3	154.6	160.2	159.2

7.4.4 Remaining tax asset lives

The AER accepts ActewAGL Distribution's proposed remaining tax asset lives as at 1 July 2014.[757] ActewAGL Distribution's proposed approach to calculating remaining tax asset lives differs from that of the AER and the AER expresses some concern with this. Nonetheless, the AER accepts the proposed remaining tax asset lives for the purposes of making the distribution determination for ActewAGL Distribution for the subsequent regulatory period, given that the difference of approach has a negligible effect on ActewAGL Distribution's total revenue requirement for the 2014-19 period.

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[757] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 8*, p. 8-14

7.5 ActewAGL Distribution’s response and revised proposal

ActewAGL Distribution rejects the AER's draft decision on the cost of corporate income tax for the 2014-19 period.

While ActewAGL Distribution accepts the AER's draft decision on the standard tax asset life for the 'equity raising costs' asset class for the 2014-19 period of 5 years, it does not accept the AER's draft decision on:

- the value of gamma, for the reasons discussed in Section 8.5 of this revised regulatory proposal;
- forecast opex for the 2014-19 period, for the reasons discussed in Chapter 3 of this revised regulatory proposal; or
- forecast capex for the 2014-19 period, for the reasons discussed in Chapter 4 of this revised regulatory proposal.

ActewAGL Distribution has updated the opening TABs as at 1 July 2014 for distribution and transmission to reflect finalised financial information on actual capex incurred during 2013/14 that has become available since its regulatory proposal for the subsequent regulatory period was prepared. The resultant roll forward of the TABs for distribution and transmission to 1 July 2014 is set out in Table 7.7 and Table 7.8 respectively.

Table 7.7 Roll forward of the distribution TAB 2009–14, ActewAGL Distribution revised proposal

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Opening TAB	412.2	452.7	499.1	532.5	563.0
plus capex	58.0	66.0	55.2	54.2	72.2
less depreciation	17.5	19.6	21.8	23.7	26.6
Closing TAB	452.7	499.1	532.5	563.0	608.6

Table 7.8 Roll forward of the transmission TAB 2009–14, ActewAGL Distribution revised proposal

$ million (nominal)	2009/10	2010/11	2011/12	2012/13	2013/14
Opening TAB	59.4	69.5	81.0	97.4	118.7
plus capex	12.6	14.4	19.8	25.2	23.2
less depreciation	2.5	2.9	3.4	3.9	4.8
Closing TAB	69.5	81.0	97.4	118.7	137.1

ActewAGL Distribution maintains its initial proposed value for gamma of 0.25 for the reasons discussed in section 8.5 of this revised regulatory proposal, and proposes revised forecasts of opex and net capex for the 2014-19 period of $359.1million ($ nominal) and $341.4 million ($ nominal) for the distribution and transmission businesses for the reasons discussed in Chapters 3 and 4 respectively.

ActewAGL Distribution sets out in Table 7.9 and Table 7.10 below the opening and closing values for the TABs for distribution and transmission respectively for each regulatory year of the 2014-19 period derived by rolling forward those TABs from 1 July 2014 using the AER's standard tax asset life for the 'equity raising costs' asset class of 5 years. These have been updated to reflect ActewAGL Distribution's revised proposed forecasts of capex for the 2014-19 period set out in Chapter 4 of this revised regulatory proposal and updated remaining asset lives using the same methodology applied in the regulatory proposal that was accepted by the AER in its draft decision.

Table 7.9 Roll forward of the distribution TAB 2014–19, ActewAGL Distribution revised proposal

$ million (nominal)	2014/15	2015/16	2016/17	2017/18	2018/19
Opening TAB	608.6	648.5	673.2	695.4	718.7
plus capex	71.3	59.8	59.5	58.7	66.5
less depreciation	31.4	35.2	37.2	35.4	36.5
Closing TAB	648.5	673.2	695.4	718.7	748.7

Table 7.10 Roll forward of the transmission TAB 2014-19, ActewAGL Distribution revised proposal

$ million (nominal)	2014/15	2015/16	2016/17	2017/18	2018/19
Opening TAB	137.1	142.8	148.6	165.1	181.8
plus capex	11.5	12.3	23.5	23.9	12.4
less depreciation	5.8	6.5	7.0	7.2	7.8
Closing TAB	142.8	148.6	165.1	181.8	186.5

ActewAGL Distribution's resultant revised proposal for the forecast cost of corporate income tax for the 2014-19 period is set out in Table 7.13.

Table 7.11 Corporate income tax building block 2014–19, distribution and transmission

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Tax Payable, Distribution	- 11.5	- 12.2	- 11.8	- 13.8	- 14.2
Value of imputation credits	2.9	3.1	2.9	3.4	3.5
Tax allowance, Distribution	8.6	9.2	8.8	10.3	10.6
Tax Payable, Transmission	1.8	2.0	2.0	2.4	2.6
Value of imputation credits	- 0.5	- 0.5	- 0.5	- 0.6	- 0.6
Tax allowance, Transmission	1.4	1.5	1.5	1.8	1.9

8 Return on capital, gamma and inflation

8.1 Introduction

In accordance with clauses 6.12.1(5), (5A) and (5B) of the Rules, the AER is required to make constituent decisions on:

- the allowed rate of return for each regulatory year of the regulatory control period in accordance with clause 6.5.2;
- whether the return on debt is to be estimated using a methodology referred to in clause 6.5.2(i)(2) and, if that is the case, the formula that is to be applied in accordance with clause 6.5.2(l); and
- the value of imputation credits (gamma) as referred to in clause 6.5.3.

This chapter sets out ActewAGL Distribution’s response to the AER’s draft decision in relation to the return on capital, gamma, equity and debt raising costs, and forecast inflation.

A summary of ActewAGL Distribution’s regulatory proposal for the subsequent regulatory period and the AER's draft decision is shown in Table 8.1.

Table 8.1 Comparison of the AER’s draft decision and ActewAGL Distribution’s rate of return position

Component	Subsequent Regulatory Proposal	draft decision	Does ActewAGL Distribution adopt the approach in the draft decision in the RRP?
Return on equity*	10.71%*	8.1%	No
Return on debt*	7.85%*	6.07%	No
Gearing	60%	60%	Yes
Gamma	0.25	0.4	No
Nominal vanilla WACC	8.99%	6.88%	No
Inflation	2.525%	2.50%	Yes

*ActewAGL Distribution's return on equity was based on an averaging period of 20 business days to 12 February 2014. ActewAGL Distribution's return on debt was based on RBA’s BBB corporate yield series with a tenor of ten years average over the 9 years and 2 months from January 2005 until the end of February 2014 without adjustment for extrapolation.

This chapter focusses on the components of ActewAGL Distribution's proposal that the AER did not accept. Each of those components are discussed in detail below in sections 8.2 to 8.6.

ActewAGL Distribution's areas of contention in respect of the AER's draft decision on rate of return are summarised below.

Return on equity

ActewAGL Distribution considers that the method adopted by the AER in its draft decision will not result in a return on equity that is consistent with the rate of return objective. In summary, this is because:

- The AER's relies on the SL-CAPM as being a superior return on equity model when it is not;
- The AER has failed to adequately have regard to all relevant estimation methods/models, market data and other evidence. In particular:
    - The AER's Rate of Return Guideline does not give any role to the Fama French (FFM) model despite substantial evidence that this model is used widely by market practitioners (see Section 8.3.5.1);
    - The Dividend Growth Model and Black CAPM are not used by the AER to inform the overall return on equity (see Section 8.3.5.1) despite substantial evidence that these models are widely used by market practitioners;
- The AER places too much weight on unreliable Australian regression data and omits relevant international evidence in determining an equity beta of 0.7 (see section 8.3.5.2); and
- The AER places too much weight on historical averages and fails to take into account relevant and current evidence in relation to the MRP, incorrectly interprets the Wrights approach and uses unreliable survey estimates in determining the MRP at 6.5 per cent which as a result does not reflect prevailing market conditions (see section 8.3.5.3).

Return on debt

ActewAGL Distribution considers that the method adopted by the AER in its draft decision will not result in a return on debt that is consistent with the rate of return objective. In summary, this is because:

- The return on debt should be based on a BBB rating or lower rather than BBB+, as the implied credit rating from the AER's draft decision is BBB (or below if parts of the draft decision cannot be implemented);
- There should not be a transition for the return on debt to be based on a 10 year averaging period as there is no principled basis to depart from the estimation of ActewAGL Distribution's return on debt without a transition (see section 8.4.5.1).

- The averaging period for financial years 2016/17, 2017/18 and 2018/19 period should be nominated before the commencement of each respective financial year (not prior to the commencement of the Regulatory Control Period) (see section 8.4.5.2). This enables the benchmark efficient entity to better match the timing of its bond issuance with its cash need than if the averaging period has to be nominated before the commencement of the regulatory control period.

Gamma

- ActewAGL Distribution maintains its position, as supported by the evidence attached as part of its subsequent regulatory proposal that gamma should be 0.25 (see section 8.5.6).

Debt raising cost

- ActewAGL Distribution contends that the AER should allow for its proposed liquidity costs and three month ahead financing costs. These are efficient costs incurred by a benchmark efficient entity (see section 8.6.4).
- Should be increased to approximately 19.75 bppa recognising that businesses incur costs when debt is rolled over and to maintain a liquidity 'buffer', not only allow for direct debt raising transaction costs.

ActewAGL Distribution adopts those parts of the AER's draft decision that are summarised below in its revised regulatory proposal. Those parts are not discussed further in the revised regulatory proposal.

Return on debt

ActewAGL Distribution accepts that part of the AER's draft decision regarding estimating the return on debt using:

- the average estimate of the return on debt (following extrapolation and annualisation) from RBA's published 10 year bond yields and Bloomberg's 7 year BVAL curve;[758]
- ActewAGL Distribution's proposed averaging period for financial years 2014/15 and 2015/16; and
- the annual updating process (however, ActewAGL Distribution does not agree that the averaging periods should be nominated prior to the commencement of the Regulatory Control Period).

Gearing ratio

[758] This is a different position compared to ActewAGL Distribution's regulatory proposal for the subsequent regulatory period.

- ActewAGL Distribution accepts a gearing ratio of 60 per cent as it is consistent with that proposed in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period

Forecast inflation

- ActewAGL Distribution accepts the AER's forecast inflation methodology as it is consistent with that proposed in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period. Accordingly, as part of this revised regulatory proposal, ActewAGL Distribution has used the forecast inflation of 2.50 per cent. This is based on the geometrical average of the RBA's Statement of Monetary Policy, published in November 2014, forecast inflation for 2014/15 and 2015/16 and the midpoint (2.5 per cent) of the RBA's inflation target of 2 per cent to 3 per cent for the 2017-24 period.

Equity raising costs

- ActewAGL Distribution accepts the equity costs raising method adopted by the AER in its draft decision as it is consistent with that proposed in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period. However, as part of this revised regulatory proposal, ActewAGL Distribution has updated the expenditure, RAB and WACC estimates to calculate revised equity raising costs.
- While ActewAGL proposed equity raising costs for its distribution, transmission and alternative control capital programs of $0.39, $0.24 and $0.12 million respectively due to the changed capital expenditure included in the draft decision, the AER’s equity raising costs allowance was significantly changed to $0.07, $0 and $0 million respectively. ActewAGL Distribution considers that the equity raising costs allowance should be adjusted in accordance with the expenditure programs, WACC and RAB values consistent with the AER’s equity raising cost methodology.

Debt raising costs

- ActewAGL Distribution accepts the debt raising transaction cost allowance of 0.091 per cent the AER has allowed for ActewAGL Distribution's debt raising costs in respect of debt transaction costs as it is consistent with that proposed in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period.

ActewAGL Distribution’s revised proposal for the rate of return in summary is shown in Table 8.2.

Table 8.2 ActewAGL Distribution proposed rate of return for 2014-19

Component	Revised Regulatory Proposal
Return on equity*	10.16%
Return on debt*	7.96%
Gearing (accepted by the AER in its draft decision)	60%
Gamma	0.25

Nominal vanilla WACC	8.84%
Inflation (accepted by the AER in its draft decision)	2.50%

*the return on equity has been estimated using an averaging period of 20 business days to 19 December2014. ActewAGL Distribution has applied an equal weight on each of the four return on equity models relied upon. The calculation of the estimate is included in attachment F14.

The return on debt was based on a simple average between RBA's BBB corporate yield series that was extrapolated and annualised with a tenor of ten years over the January 2005 to June 2014 period, and Bloomberg's fair value curve (BFV) with a change in February 2014 to the BVAL. The use of the BFV data series is consistent with what the AER has relied upon historically and what ActewAGL Distribution therefore considers should be relied upon as the historical BVAL data has been identified to be "irregularly with large 'jumps' and 'falls' apparently unrelated to market events" by CEG in attachment F2. The historical Bloomberg value has been estimated using the AER's approach to extrapolate from 7 to 10 years using the difference between RBA's 10 and 7 year estimate yield. The details of the return on debt calculation are included in attachment F11.

ActewAGL Distribution considers that its revised proposal is commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to ActewAGL Distribution in respect of the provision of standard and alternative control services. In support of its position, ActewAGL Distribution engaged SFG Consulting, CEG and Incenta Economic Consulting to review the AER's draft decision in respect of the return on equity including the individual input parameters and different models, return on debt and debt raising costs and provide their expert opinions on the AER's draft decision as summarised below and set out in Table 8.3.

Table 8.3 Advice received from expert consultants in response to the draft decision

Title	Author	Attachment
The required return on equity: Initial review of the AER draft decisions	SFG Consulting	F1
Efficient debt financing costs	CEG	F2
Debt raising transaction costs	Incenta	F3
Grant Samuel – Response to AER draft decision	Grant Samuel	F13

Based on the reports and the elaborations in this submission, ActewAGL Distribution considers that adoption of this revised proposal is the decision that contributes to the achievement of the NEO to the greatest degree.

Customer benefits/detriments

ActewAGL Distribution considers that its revised proposal is in the long term interests of its consumers. It represents the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to ActewAGL Distribution, which is necessary to facilitate access to the capital market in competition with other industries and businesses for funds necessary to undertake investments in the network during the 2014-19 period. If the rate of return is less than proposed by ActewAGL Distribution, then the efficient benchmark entity would need to constrain expenditure. This would likely lead the efficient benchmark entity to not undertake or deferring some efficient, network investment. Over the long-term this would result in a less reliable network and higher maintenance costs due to inefficient underinvestment in the network.

8.2 *Credit rating*

8.2.1 Overview

In its draft decision, the AER proposes to use a credit rating of BBB+ in estimating the return on debt.

ActewAGL Distribution maintains the position proposed in its regulatory proposal for the subsequent regulatory period, specifically a credit rating of BBB. This is supported by an expert report from CEG, included in attachment F2, which shows that the AER's draft decision would result in the benchmark efficient entity having a credit rating of BBB or below.

8.2.2 Requirements of the Rules and Law

The Rules do not contain any specific provisions in respect of the credit rating to be employed in estimating the return on debt. Rather, in accordance with clause 6.5.2(b) and (h) of the Rules, the credit rating must be determined so as to contribute to the allowed rate of return objective - that is, it should be determined for the benchmark efficient entity.

8.2.3 ActewAGL Distribution's proposal

ActewAGL Distribution proposed a credit rating of BBB and submitted an expert report from CEG to support its proposal as part of the regulatory proposal for the subsequent regulatory period.[759]

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[759] ActewAGL Distribution, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period, Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), page 255

8.2.4 AER draft decision

The AER's draft decision is that the benchmark efficient entity has a BBB+ rating. In its draft decision, the AER considers that this is consistent with the conceptual position that the benchmark efficient entity is likely to face low credit risk and notes that McKenzie and Partington found credit risk for regulated utilities is likely to be relatively small because their default risk is low and the risk of credit migrations for utilities is low and stable[760]. The AER also analysed the industry median credit ratings for a range of energy network service providers over the last 10 years and found stronger support for a credit rating of BBB+.[761] The AER also noted that since the median credit rating was BBB at the start of 2013, this indicates CEG's estimates do not include all data up to the end of the 2013 calendar year[762].

8.2.5 ActewAGL Distribution's response

ActewAGL Distribution engaged CEG to review the AER's draft decision in respect of the credit rating of the benchmark efficient entity. Based on CEG's advice on that decision, ActewAGL Distribution maintains its proposal that the benchmark efficient entity has a credit rating of BBB. CEG's report is included in attachment F2 and notes:

- that ActewAGL Distribution's implied credit rating based on credit metrics only (using Moody's methodology, converted to Standard & Poors nomenclature) would be between BB- and BBB-;
- that ActewAGL Distribution's implied credit rating based on qualitative criteria (using Moody's methodology, converted to Standard & Poors nomenclature) would be between BB and AA; and
- the combined qualitative and quantitative aspects of Moody's credit rating using Moody's weighting scheme would be between BB+ and BBB.

In conclusion, ActewAGL Distribution considers that the evidence put forward in CEG's report supports a credit rating of BBB or lower. This is further supported by the 'step change' in regulatory uncertainty that the AER's draft decision has imposed on the industry, which is discussed in section 8.3.5.2.2.

[760] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return (Appendix G)*, November, pages 3-132 to 3-133

[761] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return (Appendix G)*, November, pages 3-303

[762] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return (Appendix G)*, November, page 3-303

8.3 Return on equity

8.3.1 Overview

ActewAGL Distribution considers that the AER's draft decision does not properly recognise that no framework or specific return on equity model is perfect[763] or provides all relevant information available to estimate the return on equity. As such ActewAGL Distribution does not consider that the concept of a foundation model derives an estimate of the return on equity consistent with the NEO and that is commensurate with the rate of return objective set out in the Rules. The AER's method involves the following errors:

- the AER has erred in concluding that the SL-CAPM is the superior return on equity model;
- the AER has erred in its findings in relation to bias in the SL-CAPM;
- the AER has failed to adequately have regard to all relevant estimation methods, financial models, market data and other evidence – specifically, the AER has identified certain material as relevant but then failed to give it any meaningful role in its estimation of the return on equity;
- the AER has erred in its estimation of the SL-CAPM equity beta – neither the AER's range nor its point estimate are supported by empirical evidence;
    - the AER has not considered the substantially increasing risk for disruptive technology and 'step change' in regulatory uncertainty in its conceptual analysis of the equity beta;
    - an implicit or necessary finding made by the AER is that adopting the top of its range for the SL-CAPM equity beta will adequately correct for any bias in the SL-CAPM – there is no evidentiary basis for this finding;
- the AER has failed to take into account relevant and current evidence in relation to the MRP, and therefore its estimate of this parameter will not reflect prevailing market conditions;
- the AER has erred in concluding that its return on equity estimate is consistent with other market evidence.

[763] Michael McKenzie, Graham Partington on behalf of the Securities Industry Research centre of Asia-Pacific (Sirca) Limited, Report to the AER, Part A: Return on equity, October 2014, p 9

The correct approach to estimating the return on equity is as set out in ActewAGL Distribution's regulatory proposal on the subsequent regulatory period. That is:

- identify relevant return on equity models;
- identify relevant evidence which may be used to estimate parameters within each of the relevant return on equity models;
- estimate model parameters for each relevant return on equity model, based on relevant market data and other evidence;
- separately estimate the required return on equity using each of the relevant models; and
- synthesise model results to derive an estimate of the required return on equity.

In relation to the last step, ActewAGL Distribution has applied equal weight to the results of other return on equity models (besides the SL-CAPM). This weighting is consistent with SFG Consulting's 'default starting point'[764]. It also recognises that no model is superior or as noted by SFG Consulting:

Because all of the models have different strengths and weaknesses along different dimensions, it is impossible to identify one superior model that alone would out-perform the combined evidence of all of the relevant models.[765]

8.3.2 Requirements of the Rules and Law

Clause 6.5.2(f) and (g) of the Rules require that the return on equity be estimated such that it contributes to the achievement of the allowed rate of return objective, having regard to prevailing conditions in the market for equity funds.

That objective is that the rate of return for ActewAGL Distribution is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to ActewAGL Distribution in respect of the provision of standard control services.

The Rules also require that the AER has regard to:

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[764] ActewAGL Distribution has departed from SFG Consulting's final recommended weighting between the different models, noting that this only marginally changes the submitted revised return on equity estimate (downward).

[765] SFG Consulting, 2014, *The required return on equity for regulated gas and electricity network businesses*, May, page 89

- relevant estimation methods, financial models, market data and other evidence;
- the desirability of using an approach that leads to the consistent application of any estimates of financial parameters that are relevant to the estimates of, and that are common to, the return on equity and the return on debt; and
- any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.

8.3.3 ActewAGL Distribution's proposal

ActewAGL Distribution proposed a multi-model approach to calculate the return on equity as follows:

- identify relevant return on equity models;
- identify relevant evidence which may be used to estimate parameters within each of the relevant return on equity models;
- estimate model parameters for each relevant return on equity model, based on relevant market data and other evidence;
- separately estimate the required return on equity using each of the relevant models; and
- synthesise model results to derive an estimate of the required return on equity.

In deriving the point estimate for the return on equity, ActewAGL Distribution accorded differing weights to each of the four models it relied upon as set out in Table 10.5 of its regulatory proposal for the subsequent regulatory period.

8.3.4 AER draft decision

The AER's draft decision did not accept ActewAGL Distribution's proposal. The AER continued to rely on its foundation model approach (the AER's SL-CAPM[766]) and methodology as set out in its Rate of Return Guideline.

The AER's decision included the following conclusions:

- The SL-CAPM should be used to estimate the cost of equity because:

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[766] As noted in ActewAGL Distribution, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period, Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), page 257, ActewAGL Distribution considers that the AER is using a particular implementation of the SL-CAPM, noting that alternative proxies for the risk free rate and estimation methods for the equity beta are equally consistent with the SL-CAPM.

- it is the "*superior model in terms of estimating expected equity returns*"[767];
- The SL-CAPM, as applied by the AER, does not produce biased estimates of the required return on equity;
- Other proposed models are not fit for purpose (i.e. FFM, Black CAPM and a dividend discount model (**DDM**[768])) as these other models are focussed on explaining historic market outcomes[769].

- Equity beta of 0.7, when applied in the SL-CAPM, will deliver a return on equity that contributes to achievement of the rate of return objective. The AER considers that:

  (a) a reasonable range for the equity beta is 0.4 to 0.7;

  (b) additional information taken into account by the AER – specifically empirical estimates for international energy networks and the theoretical principles underpinning the Black CAPM – indicate that an equity beta at the top of this range is appropriate.

- MRP of 6.5 per cent to reflect prevailing market conditions. The AER's approach differs from ActewAGL Distribution's approach in a number of ways[770] including that:

  (a) the AER does not consider that the Wright approach should be used to estimate the MRP as the AER considers that the Wright approach is an alternative implementation of the CAPM, designed to produce information at the return on equity level;

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[767] AER, 2014, *Draft decision ActewAGL distribution determination 2014-19 Overview*, November, page 41

[768] The term *dividend growth model* (DGM) is used by the Australian Energy Regulator (AER), while ActewAGL Distribution, consistent with SFG Consulting, uses the term *dividend discount model (DDM).*This is because the term dividend growth model is often interpreted as a specific form of the dividend discount model, in which dividends grow at a constant rate in perpetuity from the first forecast year. In order to mitigate the risk of this interpretation, the term dividend discount model is used by ActewAGL Distribution throughout this revised submission.

[769] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-28 to 3-29. The AER notes however that the theory behind the Black CAPM was used to inform the equity beta to be used in the foundation model and the DDM was used for informing the MRP.

[770] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-38

(b) the AER does not consider that independent valuation reports should inform the MRP estimation;

(c) the AER does not agree with SFG Consulting's construction of the DDM; and

(d) the AER considers survey evidence and conditioning variables must be taken into account.

- Resulting equity risk premium (ERP) and return on equity is broadly supported by[771]:

(e) estimates using the Wright approach;

(f) the ERP range from the recent Grant Samuel valuation report for Envestra;

(g) ERP estimates from 'other market participants', including practitioners and regulators; and

(h) the fact that the regulatory regime to date has been supportive of investment.

8.3.5 ActewAGL Distribution's response

ActewAGL Distribution maintains its position as set out in its regulatory proposal for the subsequent regulatory period with one exception.

ActewAGL Distribution now proposes that equal weight should be given to the results of all return on equity models it relies upon. In so doing ActewAGL Distribution recognises that no model is clearly superior to others (or captures all relevant information). The revised weighting is consistent with SFG Consulting's 'default starting point'[772] and that no model is superior:

Because all of the models have different strengths and weaknesses along different dimensions, it is impossible to identify one superior model that alone would out-perform the combined evidence of all of the relevant models.[773]

ActewAGL Distribution's model outputs are based on independent expert advice as discussed in section 8.3.5.1.2.

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[771] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-33 to 3-35

[772] ActewAGL Distribution has departed from SFG Consulting's final recommended weighting between the different models, noting that this only marginally changes the submitted revised return on equity estimate (downward).

[773] SFG Consulting, 2014, *The required return on equity for regulated gas and electricity network businesses*, May, page 89

The AER's decision involves the following errors:

- the AER has erred in concluding that the SL-CAPM is the superior return on equity model:
  - the AER has erred in its finding that the SL-CAPM will produce unbiased estimates;
  - the AER has failed to adequately have regard to all relevant estimation methods, financial models, market data and other evidence;
- the AER has erred in its estimation of the SL-CAPM equity beta:
  - the AER's adoption of the top of its range for the SL-CAPM equity beta will not adequately correct for any bias in the SL-CAPM;
  - the AER's conceptual analysis has not taken into account the substantially increased risk faced as a result of disruptive technologies[774] and 'step change' in regulatory uncertainty;
  - the AER has erred in its estimation of the MRP;
  - the AER has erred in concluding that its return on equity risk premium (ERP) is consistent with other market evidence.

ActewAGL Distribution also draws the AER's attention to attachment F1, prepared by SFG Consulting which discusses the AEMC Rule changes, the intention with these and the AER's approach (under the new Rules) which is simply "to continue to estimate the required return on equity using the Sharpe-Lintner CAPM exclusively."[775]

ActewAGL Distribution maintains that its approach better meets the requirements of the Rules and the NEO than the AER's SL-CAPM. Accordingly, ActewAGL Distribution continues to propose to depart from the Rate of Return Guideline.

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[774] Disruptive technologies refer to technological and economic changes that are expected to challenge and transform the electric utility industry. These changes arise due to a convergence of factors, including: falling costs of distributed generation and other distributed energy resources, increasing customer, regulatory and political interest in demand-side management technologies, government programs to incentivise selected technologies and energy storage.

[775] SFG Consulting, 2015, *The required return on equity: Initial review of the AER draft decisions, Note for ActewAGL, Ausgrid, Essential Energy and Endeavour Energy*, January, page 8

8.3.5.1 *The AER has erred in concluding that the SL-CAPM is the superior return on equity model*

By relying on SL-CAPM as the foundation model the AER omits relevant information and constrains the use of information to the foundation model's parameters resulting in some information being given disproportionate weight or preventing relevant information from being used.

The AER remains of the view that "*the SLCAPM is the clearly superior model to use as the foundation model*"[776]. However, ActewAGL Distribution does not consider that this finding is supported by the evidence before the AER. In particular:

- Neither Handley nor McKenzie & Partington support the AER's view of the SL-CAPM as "superior". Indeed McKenzie & Partington note that the model "*has its weaknesses, but these are well documented and in many cases can either be diagnosed or perhaps compensated for in empirical practice*"[777]. McKenzie & Partington also state: "*The final estimate of the expected return on equity may have regard to a broad range of relevant material including a range of multifactor models such as the Fama and French (1993) and the APT of Ross (1976), inter alia. Many of these competing models nest this foundation model and so potentially make more use of available information.*"[778]

- evidence from SFG Consulting (provided with ActewAGL Distribution's regulatory proposal for the subsequent regulatory period at Attachment E3, E4, E5 and E6) identified the limitations of the SL-CAPM and explained that some of the other return on equity models were developed specifically to overcome the observed biases and anomalies in results produced by the SL-CAPM;

- the history of testing the SL-CAPM, and developing alternative models to overcome the well-recognised deficiencies in this model, is explained at some length by the Nobel Prize Committee, in the explanatory material accompanying the award of the Nobel Prize for contributions to this field, noting that "the empirical support for the model was

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[776] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-172

[777] The Securities Industry Research Centre of Asia-Pacific (Sirca), 2014, Report to the AER, Part A: Return on Equity, October, page 9

[778] The Securities Industry Research Centre of Asia-Pacific (Sirca), 2014, Report to the AER, Part A: Return on Equity, October, page 9

increasingly questioned towards the end of the 1970s"[779] and noted a number of issues with the model including that a "widely cited paper by Fama and French (1992), which convincingly established that the CAPM beta has practically no additional explanatory power once book-to-market and size have been accounted for."[780]; and

- evidence from the Black-CAPM, FFM model and the Dividend Discount Model (DDM) that clearly shows that there are limitations with the SL-CAPM:

  – it underestimates the equity beta for low beta stocks which the Black CAPM addresses;

  – it does not capture the cross sectional returns in the market to the same degree as the FFM; and

  – the AER's SL-CAPM does not capture current market conditions given that the return goes in 'lock-steps' up and down with the risk free rate, while DDMs "are more likely to reflect prevailing market conditions than other approaches"[781].

In short, ActewAGL Distribution considers that the evidence in front of the AER shows that there is no superior stand-alone model to estimate the return on equity.

> Expert reports and evidence addressing the AER's view that the SL-CAPM is a superior model:
>
> - Attachment F1 – SFG Consulting, The required return on equity: response to the AER draft decision
> - Attachment F4: The Royal Swedish Academy, Scientific Background on the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2013
> - ActewAGL Distribution, Regulatory proposal for the subsequent regulatory control period, Attachment E3, E4, E5 and E6.

[779] See Attachment F4, Kungliga Vetenskapsakademien, 2013, *Scientific Background on the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2013, Understanding asset prices, compiled by the Economic Sciences Prize Committee of the Royal Swedish Academy of Sciences*, October, page 38

[780] See Attachment F4, Kungliga Vetenskapsakademien, 2013, *Scientific Background on the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2013, Understanding asset prices, compiled by the Economic Sciences Prize Committee of the Royal Swedish Academy of Sciences*, October, page 39

[781] AER, 2013, *Rate of Return Guideline, Explanatory Statement*, *Appendix D*, December, page 85

8.3.5.1.1 The AER has erred in its finding that the SL-CAPM will produce unbiased estimates

The AER rejects ActewAGL Distribution's contention in the regulatory proposal for the subsequent regulatory period that the SL-CAPM will produce biased estimates[782] and states:

> "*There is no compelling evidence [that] the return on equity estimate from the SLCAPM will be downward biased given our selection of input parameters*."[783]

It is not entirely clear what the AER is basing its statements upon. If the AER is saying that, in general, the SL-CAPM will produce unbiased estimates, ActewAGL Distribution considers that would involve an error of fact, in that evidence was provided with ActewAGL Distribution's regulatory proposal for the subsequent regulatory period of bias in the SL-CAPM – this included evidence from SFG Consulting, referring to the extensive empirical research in this respect, such as the work of Black, Jensen and Scholes (1972), Friend and Blume (1970) and Fama and Macbeth (1973);[784]

Alternatively, if the AER is saying that to the extent that the SL-CAPM may produce biased estimates, the AER's selection of input parameters adequately corrects for any bias, ActewAGL Distribution considers there is no basis for that statement because the AER has not sought to quantify the effect of SL-CAPM bias – as noted by the AER: "*the theoretical principles underpinning the Black CAPM demonstrate that market imperfections could cause the true*

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[782] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-172

[783] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-48

[784] ActewAGL Distribution, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period*, *Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), Attachment E3

(unobservable) expected return on equity to vary from the SLCAPM estimate… However, while the direction of this effect may be known, the magnitude is much more difficult to ascertain."[785]

Further, ActewAGL Distribution notes that it provided return on equity estimates for the Black CAPM, FFM and DDM in its regulatory proposal for the subsequent regulatory period (and in attachment F1 of this revised submission) that transparently shows what return on equity each model generates. For this revised submission, SFG Consulting shows that the SL-CAPM (using an equity beta of 0.82) generates a return on equity estimate that is about 0.7 percentage points below the average of the four models considered by the AER and notes:

> *…if the AER is to have regard to evidence from the Black CAPM, it should be transparent about what it considers that evidence to be. This requires nothing more than setting out what the AER considers to be the required return (or adjusted beta) that is supported by the Black CAPM. If the AER does not accept the SFG estimate of the zero-beta premium it should state why (rather than simply noting that there are other estimates of the zero-beta premium that it considers to be implausible) and set out what it considers to be a more reasonable estimate of the zero-beta premium. At the very least, the AER should report the effect that its consideration of the Black CAPM evidence has had on its calculation of the allowed return on equity. In its recent draft decisions there is no way for stakeholders to determine (a) what return on equity (or beta) the AER considers to be supported by the Black CAPM or evidence, or (b) what weight the AER has applied to the Black CAPM evidence. Consequently, there is no means for determining whether the AER's interpretation of the Black CAPM evidence, or whether the weight the AER has applied to it, is reasonable.* [786]

ActewAGL Distribution considers that this point also applies to the FFM and DDM and that the AER has not sought to quantify the bias of the SL-CAPM. Given this, and in the absence of any other evidence, the AER cannot reasonably be satisfied that choosing the top of its equity beta range will adequately correct for such bias.

[785] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-267

[786] SFG Consulting, 2015, *The required return on equity: Initial review of the AER draft decisions*, January, page 17

Expert reports and evidence addressing the AER's view that the SL-CAPM produces unbiased estimates:

- Attachment F1 – SFG Consulting, The required return on equity: response to the AER draft decision
- ActewAGL Distribution, Regulatory proposal for the subsequent regulatory control period, Attachment E3, E4, E5 and E6.

ActewAGL Distribution notes that in considering the issue of potential bias, the AER states it considered a wide range of material including[787]:

1. if there is evidence returns set previously based on the SL-CAPM have discouraged investment;
2. whether the ERP appears appropriate;
3. if anything the AER is doing in applying the SL-CAPM appears inconsistent with common financial market and investor practice; and
4. if the individual input parameters into the SL-CAPM appear reasonable.

The first of these considerations – whether returns set previously have discouraged investment – is irrelevant and does not provide any basis for finding that the SL-CAPM is unbiased. Rates of return in previous periods have been estimated with different input parameters (in particular, a higher equity beta) and in different market conditions (with higher prevailing risk-free rates). Indeed, market conditions are currently different which SFG Consulting notes:

> *Logically, the fact that the Sharpe-Lintner CAPM may have provided an appropriate allowed return on equity during a period of normal market conditions, and during a period when the AER was adopting a materially higher equity beta than it now proposes, does not imply that it will provide an appropriate estimate in historically unique market conditions, especially if parameters are measured inconsistently. The inability of a single model, by itself, to be able to provide an appropriate allowed return on equity in all market conditions is what led the AEMC to require consideration of the range of relevant financial models under the new Rules.*

[787] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-51

That is, the question is not whether the Sharpe-Lintner CAPM may have produced reasonable estimates in past market conditions, but whether it alone is likely to provide the best estimate (i.e., better than the estimate that would be obtained from having regard to a range of relevant models) in the prevailing conditions. Indeed, in its Final Determination, the AEMC refers to the need to have regard to the prevailing conditions no fewer than 15 times.[788]

The issues ActewAGL Distribution has with the other three considerations are addressed below. The second and third considerations are addressed in section 8.3.5.4. The input parameters used by the AER are discussed in sections 8.3.5.2 and 8.3.5.3 below where ActewAGL Distribution concludes that the AER has erred in determining the equity beta and the MRP.

8.3.5.1.2 <u>The AER has failed to adequately have regard to all relevant estimation methods, financial models, market data and other evidence</u>

The draft decision does not rely on the FFM, Black CAPM and the DDM, to inform the AER's overall return on equity estimate as a cross-check of the SL-CAPM. Instead, it uses the Black CAPM to inform its choice of the equity beta point estimate and it uses the DDM to inform its MRP. The AER did not rely at all on the FFM.

<u>FFM – Fama French Three Factor Model</u>

The AER does not rely on the FFM to inform its estimate of the return on equity of the benchmark efficient entity for the following key reasons:

- *it does not appear sufficiently robust and is sensitive to different estimation periods and methodologies*
- *it is not clearly estimating ex ante required returns*
- *it suffers a lack of theoretical foundation which might explain the instability of parameter estimates*
- *it is relatively complex to implement.*[789]

[788] SFG Consulting, 2015, *The required return on equity: Initial review of the AER draft decisions*, January, page 9

[789] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-53

ActewAGL Distribution engaged SFG Consulting to review the concerns raised by the AER and its report is included in attachment F1.

In summary, on the first point, ActewAGL Distribution considers that this is irrelevant given that the SL-CAPM also can produce different results depending upon which period data that is examined. ActewAGL Distribution further notes that if the AER considers that there is some problem with any estimation process, it should indicate what exactly it is, rather than state that estimates might vary if they were computed differently.

On the second point, ActewAGL Distribution considers that this concern would also apply to the SL-CAPM, historical estimates of the MRP and the equity beta that the AER uses to estimate a prevailing estimate of the return on equity.

In relation to the claimed lack of theoretical foundation of the FFM, ActewAGL Distribution refers to its regulatory proposal on the subsequent regulatory period attachment E5, which in detail explains that the FFM is based on theoretical foundation being the asset pricing theories developed during the 1970s, the intertemporal CAPM and the arbitrage pricing theory.

On the final point, ActewAGL Distribution does not consider a model capable of a valuable contribution to the allowed rate of return objective should be dismissed due to its perceived complexities to implement. SFG Consulting also notes that it is not more complex to implement:

> *…the Fama-French model can be estimated in exactly the same way as the Sharpe-Lintner CAPM. Both require betas to be estimated using regression analysis and factor premiums to be estimated using historical returns data. The Sharpe-Lintner CAPM is simply a special case of the Fama-French model, wherein it is assumed that the SMB and HML factor premiums are zero. Consequently, the Fama-French model is not more complex to estimate than the Sharpe-Lintner CAPM – the same estimation approaches simply have to be applied three times instead of once.*[790]

Black CAPM

The AER only uses the Black CAPM model to inform its choice of the equity beta point estimate. The AER is of the view that empirical estimates of the return on equity from the Black CAPM are not suitable for any use for the following key reasons:

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[790] SFG Consulting, 2015, *The required return on equity: Initial review of the AER draft decisions*, January, page 22

- *the model is not empirically reliable*
- *the model is not widely used to estimate the return on equity by equity investors, academics or regulators.* [791]

The reason the AER appears to consider the Black CAPM as not empirically reliable is because the estimate of the zero-beta premium is unreliable, referring to different estimates from different consultants that DNSPs have relied upon, though noting that the AER's view on SFG Consulting's estimate of the zero-beta premium is "plausible". SFG Consulting has reviewed the AER's reasons and states:

> *When faced with different approaches that produce different estimates of a parameter, the appropriate response is to consider the relative merits of each approach. The AER does not reject the SFG estimate because it considers the estimation approach to be inappropriate or because it considers the estimate to be implausible – it rejects the SFG estimate because there are other estimates that use different approaches that produce estimates that the AER considers to be implausible.*
>
> *The AER's approach in this regard is also inconsistent with its approach to estimating Sharpe-Lintner CAPM parameters. There are a range of approaches that can be used to estimate beta and MRP that produce a wide range of estimates for each of those parameters. This does not lead the AER to conclude that the Sharpe-Lintner CAPM is empirically unreliable and should not be estimated. Rather, the AER presents its reasons for disregarding those techniques and estimates that it considers to be unreliable and its reasons for giving more weight to the approaches and estimates that it considers to be more reliable. It is not clear why precisely the same approach could not have been applied to the zero-beta premium.*[792]

In relation to the use of the Black CAPM, ActewAGL Distribution refers to SFG Consulting's expert report submitted (attachment E4) as part of its regulatory proposal for the subsequent regulatory period. Moreover, in the report provided as part of this revised submission, SFG Consulting notes that it is common for US regulatory cases to use what is known as "the empirical CAPM", which is the CAPM with an intercept above the contemporaneous risk free rate

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[791] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-57

[792] SFG Consulting, 2015, *The required return on equity: Initial review of the AER draft decisions*, January, page 8 to 13

so in other words a model consistent with the Black CAPM empirical evidence. ActewAGL Distribution refers for further details to attachment F1.

<u>Dividend Discount Model - DDM</u>

In relation to the DDM, the AER uses it to inform its MRP, but remains of the view that DDM based empirical estimates of the return on equity for a benchmark efficient entity is not suitable for any regulatory purposes for the following reasons:

- *The models are not robust given they are highly sensitive to input assumption in relation to the short term and long term growth rate of dividends. This makes the models highly sensitive to potential error in inputs.*
- *The models are highly sensitive to changes in the risk free interest rate.*
- *The models may generate volatile and conflicting results.*[793]

The AER was also critical of SFG's DDM model that ActewAGL Distribution submitted as part of its regulatory proposal for the subsequent regulatory period and McKenzie and Partington also considered the model and noted "*We are not convinced that the use of the SFG DGM model will lead to a materially better cost of equity than the AER's approach*".[794]

SFG Consulting has reviewed the AER's reasons to disregard the model ActewAGL Distribution proposed to be used to estimate the return on equity as well as SFG Consulting's specific version of the DDM. SFG Consulting agrees that the DDM, like all models, is sensitive to input assumptions. However, in relation to the sensitivity to change in the risk free rate, the DDM actually tends to reduce the sensitivity of the allowed return to other methods employed by the AER. Further, the view that some versions of the DDM may have internally inconsistent modelling specifications is not a reason to reject all DDM. Further details in response to the AER's concerns are included in attachment F1.

In light of SFG Consulting's conclusions discussed above in relation to each return on equity model, ActewAGL Distribution considers there is substantial evidence that supports the use of

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[793] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-61

[794] Michael McKenzie and Graham Partington on behalf of the Securities Industry Research Centre of Asia Pacific (SIRCA) Limited, *Report to the AER Part A: Return on Equity*, October 2014, p. 40

more than just one return on equity model to estimate the return on equity as there is 'no superior' model that estimates the return on equity.

Expert report and evidence addressing the AER's position not to rely on the FFM, Black CAPM and DDM to estimate the overall return on equity • Attachment F1: SFG Consulting: The required return on equity: response to the AER draft decision

In the alternative, ActewAGL Distribution considers that if the AER maintains its reliance on the foundation model, it should use additional return on equity models/approaches to cross check the overall return on equity outcome. It is not sufficient to cross-check some input parameters at some specific stages of the AER's six step process of its foundation model approach as this does not ensure that the overall outcome of the return on equity actually is commensurate with the efficient financing costs of a benchmark efficient entity. This position was supported by SFG Consulting in its expert report attached to ActewAGL Distribution's regulatory proposal for the subsequent regulatory period:

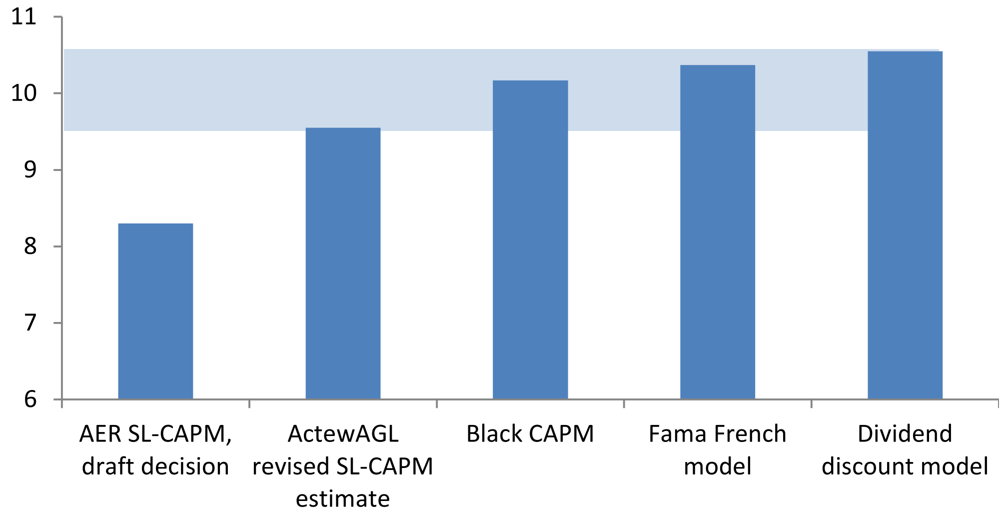
> *Because all of the models have different strengths and weaknesses along different dimensions, it is impossible to identify one superior model that alone would out-perform the combined evidence of all of the relevant models. This is consistent with the AEMC's views that:*
>
> > *a) "no one method can be relied upon in isolation to estimate an allowed return on capital that best reflects benchmark efficient financing costs;" and that*
> >
> > *b) The NEO, NGO and RPP can only be achieved by obtaining "the best possible estimate of the benchmark efficient financing costs," which in turn requires the use of a range of financial models.*
>
> *Consequently, our view is that any approach that adopts a single "superior" model, and which effectively disregards other relevant models, will not provide the best possible estimate of "the best possible estimate of the benchmark efficient financing costs." Any sub-standard estimate of financing costs will inevitably lead to investors being either under- or over-compensated – neither of which are in the long-run interests of consumers.*[795]

[795] SFG Consulting, 2014, *The required return on equity for regulated gas and electricity network businesses*, May, page 89

Accordingly, ActewAGL Distribution's position is that the AER should cross-check the foundation model's (i.e. SL-CAPM) return on equity estimate with the FFM, DDM and the Black CAPM models.

If the AER were to do so, it would note that its return on equity estimate from the SL-CAPM generates the lowest estimate of these models as shown in Figure 8.1. In ActewAGL Distribution's view, the AER therefore has not estimated a rate of return that is consistent with the rate of return objective.

Figure 8.1 Comparison of return on equity estimates with the AER's foundation model



One reason the AER's foundation model generates the lowest estimate of the return on equity is that the equity beta and MRP input parameters used by the AER do not incorporate all relevant information. ActewAGL Distribution provides some specific comments below in sections 8.3.5.2 and 8.3.5.3 on these two parameters.

8.3.5.2 *The AER has erred in its estimation of the SL-CAPM equity beta*

The AER determines that an equity beta of 0.7, when applied in the SL-CAPM, will deliver a return on equity that contributes to achievement of the rate of return objective.

The AER states that "*the empirical studies show an extensive pattern of support for an empirical equity beta within a range of 0.4 to 0.7*"[796]. This is inconsistent with:

- the recommendation of the AER's consultant, who concludes: "*In the opinion of the consultant, the majority of the evidence presented in this report, across all estimators, firms and portfolios, and all sample periods considered, suggests that the point estimate for β lies in the range 0.3 to 0.8.*"[797]
- the evidence from SFG Consulting and CEG, based on a larger sample including international businesses. This evidence indicates an equity beta in the range of 0.82 to 0.91.

For the reasons expressed below ActewAGL Distribution considers that the adoption of its approach to estimating the equity beta contributes an equity beta to the allowed rate of return that achieves the rate of return objective.

8.3.5.2.1 <u>The AER's adoption of the top of its range for the SL-CAPM equity beta will not adequately correct for any bias in the SL-CAPM</u>

The AER considers that:

- "*the best empirical estimate*" of the SL-CAPM equity beta from Henry's report is 0.5[798]
- the theory of the Black CAPM points to an estimate of the SL-CAPM beta that is above the best estimate indicated by Henry's analysis[799]; and
- international empirical estimates also provide "*limited support*" for an equity beta point estimate towards the top of the AER's range[800].

[796] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-268

[797] Ólan T. Henry, University of Liverpool Management School, Estimating β: An update, April 2014, p 63

[798] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-266

[799] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-267

Firstly, ActewAGL Distribution considers that Henry actually does not make any recommendation as to the "best empirical estimate" of beta. As noted above in section 8.3.5.2, Henry recommends a range of 0.3 to 0.8.

Secondly and more fundamentally, the AER cannot reasonably be satisfied that adopting a figure somewhere above the "*best empirical estimate*" will correct for either the limitations of the SL-CAPM (as indicated by Black CAPM theory) or the limitations of Henry's dataset. The magnitude of the adjustment from the "*best empirical estimate*" is clearly limited by the way in which the AER's range is defined, and the AER cannot know whether its adjustment is sufficient to address the issues it has identified.

Thirdly, SFG Consulting has reviewed the AER's draft decision. SFG Consulting notes that the "*evidence on beta from international comparators overwhelmingly supports an estimate materially above the AER's primary estimate of 0.7*."[801] This is further addressed in the expert report by SFG Consulting included in attachment F1 which shows that the AER has erred in concluding that there is limited support for an equity beta point estimate toward the top of the AER's range.

8.3.5.2.2 <u>The AER's conceptual analysis has not taken into account the substantially increased risk faced as a result of disruptive technologies and increased regulatory risk</u>

Disruptive technologies

In its draft decision the AER states that there are reasonable conceptual grounds to expect the equity beta of a benchmark efficient regulated energy network to be below 1.0[802]. This is supported by a report from McKenzie and Partington. ActewAGL Distribution considers that the AER's conceptual analysis and discussion in section D.1.3 of its draft decision is based on historical circumstances and do not acknowledge that the uncertainty currently confronting the energy industry, as summarised in this report in Table 8.4. In the last five years**,** ActewAGL Distribution considers that the general (i.e. systematic) risk and uncertainty have increased substantially for energy distribution businesses in Australia through the development of more efficient off-grid solutions and disruptive technologies. This is a new and significant risk that was

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[800] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-267

[801] SFG Consulting, 2015, *The required return on equity: Initial review of the AER draft decisions*, January, page 27

[802] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-242

not foreshadowed by regulators a few years ago. Accordingly, there is a strong conceptual argument that the uncertainty as well as the systematic risk has increased rather than decreased since the last review of the WACC by the AER in 2009. Also, ActewAGL Distribution does not consider that the statistical based equity beta observations have captured this increased risk as the ranges explored rely on much longer data series. Further, this is a relatively new risk that may not have been fully appreciated and absorbed by the capital market via higher equity beta observations.

This development has been well documented in many reports that are attached to this revised regulatory proposal (see papers referred to in Table 8.4). The financial risks created by disruptive challenges include declining utility revenues, increasing costs, lower profitability potential and increased possibility that utilities will not fully recover the cost of long lived investments.

As more off-grid solutions and disruptive technologies programs capture 'market share', for example, it can be expected that utility revenues will be reduced as customers disconnect from the network. Adding the higher costs to integrate new energy resources and increasing subsidies for demand side management technologies will result in the potential for reduced profitability and, credit metrics. For an industry that usually recovers the cost for its investments over a 40-60 year period, this development needs to be considered from a holistic perspective as the current regulatory framework may not be well positioned to address this increased risk and off-grid 'competition'.

With new storage capacity technologies expected to become available in the coming years at significantly lower costs[803], network providers will experience competition from alternative technologies that enables by-passing of the distribution network. The AER's conceptual equity beta analysis does not take this fundamental industry challenge into consideration. ActewAGL Distribution also considers that the AER's empirical analysis, that mostly builds on historical data before this industry challenge emerged, and therefore does not take this risk into consideration.

ActewAGL Distribution attaches five reports that discuss the trend of increasing risk and uncertainty facing the energy distribution industry. These reports are summarised in Table 8.4.

[803] For example, Tesla Motors is currently building a $5 billion advanced battery factory in Nevada that is expected to reduce costs for storage substantially. The factory is expected to produce more than all of the current lithium-ion battery production in the world today.

Table 8.4 Summary of reports showing increased risk from disruptive technologies to electricity distribution businesses

UBS 2014, *Global Utilities, Autos and Chemicals*, August UBS has been conducting research into solar PV, battery storage and electric vehicles (EV) for over two years. In this report, it forms the view that: "Solar panels and batteries will be disruptive technologies. Solar is at the edge of being a competitive power generation technology. The biggest drawback has been its intermittency. This is where batteries and electric vehicles (EVs) come into play. Battery costs have declined rapidly, and we expect a further decline of >50% by 2020. … we also expect the cost of stationary batteries to drop c50% by 2020. Based on our proprietary analysis, battery storage should become financially attractive for family homes when combined with a solar system (and an EV)." Using their own model, UBS has estimated that: "The combination of and [sic] EV + solar + battery should have a payback of 7-11 years, depending on the country-specific economics." And that, in relation to Australia: "Outside Europe, we think the US (south-west) and Australia could be amongst the early movers." Going into more financial analysis, using their model, UBS estimates that: "…combined investment in a solar system, stationary battery and EV would have a 7.3% ROI (before interest) in 2020 (vs. 1.8% today). … by 2020, the payback time could drop to c7-8 years – in other words, the owner would receive free electricity for another c12-13 years." This is a major incentive for customers to go off grid, a point UBS makes explicitly: "By 2025, everybody will be able to produce and store power." In terms of solar panels, UBS state that: "solar panels have become a commodity. The cost of solar panels has dropped c85% over the past 7 years – a decline that even solar enthusiasts had under-estimated. And the cost degression is likely to continue on further economies of scale and innovation (better solar cell performance)." And in terms of batteries, the more than 50% estimated reduction in prices by 2020 is, in part, driven by: "The Tesla Gigafactory [which] aims to double battery production capacity in 3-4 years and should be a significant catalyst in stimulating the market. … We see battery costs moving down from US$360/kWh today to US$200/kWh by 2020, and as low as US$100/kWh within 10 years. … Umicore and Tesla have both indicated that the chemistry and materials science needed to significantly reduce battery costs has already been discovered. Industrialisation is now the final barrier." UBS does note that this development is a 'net opportunity' for the industry, but clearly this shows that uncertainty and prevailing risk has increased. UBS states: "Our view is that the 'we have done it like this for a century' value chain in developed electricity markets will be turned upside down within the next 10-20 years, driven by solar and batteries. … Utilities will be the facilitators of a decentralised electricity system"

UBS's full report is included in attachment F10.
Kerin, R. 2014, *IBIS World Industry Report D2630, Electricity Distribution in Australia*, December Mr Kerin discusses the risk to distribution and generation from disruptive technologies and that these will have negative financial implications. It is ActewAGL Distribution's view that this conceptually shows that the systematic risk is increasing as this is a risk that is not possible to diversify away. This will increase the risk of the industry market portfolio and result in a higher correlation with the overall market index. In particular, Kerin reports that: "The growth of renewables, particularly the installation of small-scale solar power generation by households, is likely to challenge the structure of current electricity transport networks over the next five years." Kerin discusses the risk to distributors of solar generation: "Trends in electricity demand are likely to challenge the business models of distribution networks in the next five years. The demand for commercially generated electricity is declining, in part due to household adoption of small-scale photovoltaic systems (solar panels). As adoption of this technology grows, the flow of electricity on distribution networks will change, and charging practices may need to be adjusted." He also discusses the revenue and profitability implications of these changes: "Households with solar panels reduce their exposure to network costs and wholesale energy prices in the current system. This undermines the principles of variable pricing and could lead to revenue shortfalls for distribution networks." Kerin's future outlook is that: "As the industry and its regulators adapt to new market conditions, industry profitability is expected to come under pressure." In other words, this is an increase in the risk of investing in a distribution network. Kerin goes on to argue that changes to regulation: "…will reduce profitability and therefore the industry's contribution to the economy. Industry value added is forecast to grow at an annualised 0.6% over the 10 years through 2019-20. This is slower than the growth of the Australian economy over the same period, which is forecast to grow at an annualised 2.7%. Therefore the industry is expected to underperform the economy." This underperformance will affect credit ratings and so make it more costly to raise funds. The full report is included in attachment F7.
Citi 2013, *Energy Darwinism*, October Citi believes that technology substitution is already happening: "[The] substitution effect is already happening to a degree which we believe is not widely recognised, and moreover sizeable investment decisions being taken now by E&P companies, oil majors, utilities and renewables developers will be affected by the changing shift within the lifecycle of those projects, and in some cases in the early years of those projects." Citi refers to the German experience, in that: "In just 6 years, there has been a fundamental shift in the Germany electricity generation mix… in 2007 annual solar installations [growth] were relatively limited at just 1.4GW, but this grew to 7.4GW per annum in just 3 years, and stayed at that level for the next 3 years…" They go on to look at electricity storage as the next large technology adoption: "If, as we suspect, storage is the next solar boom and becomes broadly adopted in markets such as Germany, the electricity load curves could once again change dramatically causing more uncertainty for utilities and more disruption to fuel markets. … while storage is still very much a nascent industry, we should remind ourselves that this was the case with solar in Germany only 5-6 years ago." Citi also discusses the constantly improving price competitiveness of solar generation: "The rate at which the price of solar panels has reduced has exceeded all expectations, resulting in cost parity being achieved in certain areas much more quickly; the key point about the future is that these fast 'learning rates' are likely to continue, meaning

that the technology just keeps getting cheaper. At the same time, the alternatives of conventional fossil fuels are likely to gradually become more expensive … These dramatic cost reductions mean that solar is already competitive in many regions at a domestic level" According to Citi (Figure 66), Australia has already reached 'socket' parity. Citi goes on to discuss the financial challenges of the electricity generation industry, but similar points can be made for distribution networks in terms of customers rather than volumes: "It is a structural challenge to the sector's financial model when an industry with such a high fixed cost and capital cost base, which is remunerated on a volumetric basis, is seeing its market share of volumes in steady decline. It is also a structural challenge to the sector's operating model as the core purpose up until now … is taken up by decentralised entities or even the consumers themselves in the case of solar or CHP." The full report is included in attachment F8.
Rocky Mountain Institute, Homer Energy and Cohnreznick Think Energy 2014, The economics of grid defection, February The authors of this report discuss the ability of electricity consumers to defect from the grid: "Equipped with a solar plus-battery system, customers can take or leave traditional utility service with what amounts to a "utility in a box."" They elaborate on this by stating that: "the point at which solar-plus-battery systems reach grid parity—already here in some areas and imminent in many others for millions of U.S. customers—is well within the 30-year planned economic life of central power plants and transmission infrastructure. Such parity and the customer defections it could trigger would strand those costly utility assets. Even before mass defection, a growing number of early adopters could trigger a spiral of falling sales and rising electricity prices that make defection via solar-plus-battery systems even more attractive and undermine utilities' traditional business models." Having undertaken significant analysis of possible future paths, they reach three conclusions: "1. Solar-plus-battery grid parity is here already or coming soon for a rapidly growing minority of utility customers, raising the prospect of widespread grid defection. … 2. Even before total grid defection becomes widely economic, utilities will see further kWh revenue decay from solar-plus-battery systems. … 3. Because grid parity arrives within the 30-year economic life of typical utility power assets, it foretells the eventual demise of traditional utility business models." Even though this report is written with the US market in focus, ActewAGL Distribution notes that the examples provide another example of rapid technological development that is increasing the uncertainty for the energy industry. The full report is included in attachment F9.
Rogers, M. 2012 *Energy=innovation: 10 disruptive technologies* ActewAGL Distribution considers that this report shows how soon disruptive technologies could start to clearly affect the energy distribution businesses. Mr. Roger's view is that five technologies are expected to be most disruptive in the next five years. "Most of the technologies that could prove disruptive are familiar—including unconventional gas, electric vehicles, solar, and lighting from light-emitting diodes… … in some cases, the shift could begin as early as 2015." He goes on to say that there is a 'tipping point' rather than a steady transition to a disruptive technology: "…developing technologies may remain uneconomical on average, even as leading innovators approach breakthroughs. But once a technology delivers cost and performance that is materially superior to the status quo, it may well be adopted en masse. Such technologies can render existing ways of doing business untenable in less than a decade…" Further, Mr Rogers adds that:

“Competition among technologies … raises the bar and often accelerates innovation.”

This would amplify the ‘tipping’ of the economy into such a technology. In terms of energy storage, Rogers shows there has been a sharp decline in battery prices, a technology which is a potential substitute to distribution services:

> “In 2009, advanced batteries cost about $1,000 per kilowatt hour. New battery-manufacturing facilities were able to deliver batteries at just over $500 per kilowatt hour in 2010, and the price could drop to $350 per kilowatt hour when these facilities reach full-scale production over the next few years.”

In terms of distributed generation, Rogers shows the sharp decline in prices of solar power generation:

> “The installed cost of solar power has fallen to about $2.50 per watt in 2012, down from $4 per watt in 2011, and from about $7 to $8 per watt as recently as 2009.
>
> … potentially driving solar prices down to $1.50 per watt by 2015 and to less than $1 per watt by 2020.”

The full report is included in attachment F6.

ActewAGL Distribution’s contends that the issues discussed in Table 8.4 have implications for regulated utilities beyond the equity beta, and which are currently not considered by the AER. These issues have the potential to completely change distribution businesses, and it is ActewAGL Distribution’s view that the AER, and AEMC, need to respond to these issues before they impact the viability of these businesses. One part of any such response may be to reduce the timeframe over which distribution assets are depreciated.

Increased regulatory risk

ActewAGL Distribution accepts that in the past highly regulated infrastructure assets (such as energy distribution assets) were commonly considered a low-risk investment with financing obtained at relatively low-cost and relatively stable distributions to investors. The stability and predictability of the regulatory regime is a criterion considered by Moody’s as discussed in attachment F2.

The changes to the regulatory framework implemented through the AEMC's 2012 Rule amendments give more discretion to the AER and, in this respect, are new and untested. ActewAGL Distribution acknowledges that greater regulatory discretion may lead to better regulatory decisions and outcomes but only where those decisions are well-principled, are transparent, accord with international best practice and are consistent with the NEL.

ActewAGL Distribution considers that the AER’s draft decisions for ActewAGL Distribution and the NSW businesses do not represent such decisions, as in those draft decisions the AER:

- Imposes opex reductions in sole reliance on econometric benchmarking results using unreliable data;
- Imposes capex reductions of 35 per cent on the basis of flawed analysis and incorrect data;

- Expects largely fixed-cost businesses to make extremely large P_0 adjustments in an unduly short timeframe in order to manage these harsh cuts in its expenditure allowance;
- Implements the AER's substantive (and un-foreshadowed) departure from its prior regulatory practice for determining expenditure allowances on a retrospective basis with the consequence that the businesses' expenditure allowances for the SRP are materially lower than even the AER's own estimates of efficient costs for the period;
- Fractures the strong regulatory incentives otherwise in place for the businesses to reveal their efficient costs. In this context, In this context, Mr. Houston notes:

  A failure to adjust revenue to achieve the sharing ratio operating under the 2008 EBSS increases the level of uncertainty in the regulatory environment and, in so doing, substantially increases the level of regulatory risk. Regulatory risk increases the prospect of investors' expectations as to the return on or of capital for a particular project not being met, and so increases a regulated firm's cost of providing capital, to the detriment of the long term interests of consumers.[804]

It follows, therefore, that the legacy argument that business specific risk could be diversified away no longer holds because the AER's draft decisions for ActewAGL Distribution and the NSW DNSPs apply to such a significant part of the energy distribution industry in Australia and the substantive change of regulatory approach effected in those decisions will presumably also be applied by the AER in decision-making for other NEM DNSPs. Given this, the AER's draft decision represents a 'step change' increase in regulatory uncertainty that, in turn, increases the systematic risk for the benchmark efficient entity. ActewAGL Distribution therefore considers that, if (contrary to ActewAGL Distribution's contentions in this revised regulatory proposal) the AER proceeds to make its final decision on the basis of the Draft Decision, this resultant 'step change' in regulatory uncertainty and systematic risk requires compensation via an increase in the equity beta

Summary disruptive technologies and increased regulatory risk

ActewAGL Distribution considers that the risks related to technology development and structural changes discussed above questions the validity of the AER's conceptual analysis conclusion to expect the equity beta of a benchmark efficient regulated energy network to be below 1.0. The evidence indicates, on a conceptual level, that the systematic risk to the energy distribution businesses has increased, which contrasts with the AER's decision to lower ActewAGL Distribution's equity beta to 0.7. ActewAGL Distribution also considers that these significant

[804] See Attachment C1, HoustonKemp, 2015, *Opex and the efficiency benefit sharing scheme*, January, page 26

challenges for the industry need to be considered by the AER not only in relation to the equity beta, but also in relation to how the industry generally is regulated.

8.3.5.2.3 Asymmetrical risk on beta

ActewAGL Distribution also continues to consider that the equity beta is subject to asymmetrical risk. This point was raised in its regulatory proposal for the subsequent regulatory period and ActewAGL Distribution does not consider that the AER has provided any evidence to the contrary.

8.3.5.3 *The AER has erred in its estimation of the MRP*

The AER concludes that a MRP of 6.5 per cent reflects prevailing market conditions. The AER's approach differs from ActewAGL Distribution's position as discussed in section 8.3.4 above. This section will address each of those differences in turn.

For the reasons expressed below ActewAGL Distribution considers that the adoption of its approach to estimating the MRP contributes a MRP to the allowed rate of return that achieves the rate of return objective.

8.3.5.3.1 The AER's rejection of the Wright approach

The AER does not take into account the Wright approach when estimating the MRP, because it considers that the Wright approach should inform the overall return on equity only. The AER refers to the Wright approach as "*an alternative implementation of the SLAPM [sic] designed to provide information at the return on equity level*" [805].

This appears to be an incorrect interpretation of Wright's work. Wright did not develop an alternative implementation of the SL-CAPM. Wright simply proposed an alternative method of estimating the MRP for use in the SL-CAPM – as the difference between the historical average market return and the current risk free rate – on the basis that market returns may be more stable over time than excess returns. In its regulatory proposal on the subsequent regulatory period, ActewAGL Distribution attached an expert report from SFG Consulting (attachment E3). In that report SFG Consulting noted:

[805] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-38

a) There are two approaches for estimating MRP from the historical data. The Ibbotson approach assumes that the MRP is constant across all market conditions and estimates the MRP as the mean historical excess return. At the other end of the spectrum, the Wright approach assumes that the required return on the market is constant and estimates the MRP by subtracting the contemporaneous risk-free rate.

b) In our view, the Ibbotson and Wright approaches should both be used to inform the estimate of MRP for use in a Sharpe-Lintner CAPM foundation model.

c) Moreover, Lally (2012 MRP, 2013 MRP) also recommends that the Ibbotson and Wright approaches should both be used to estimate MRP, and the Wright approach is also used extensively by UK regulators to estimate the required return on the market and the MRP.[806]

ActewAGL Distribution therefore maintains its view that the Wright approach should be used to estimate the MRP. SFG Consulting has reviewed the AER's draft decision in relation to the Wright approach. SFG Consulting notes:

the AER uses the Ibbotson approach to inform its estimate of MRP, and effectively relegates the Wright approach in the manner described below. The result is that:

a) The AER concludes that the historical stock returns data supports an MRP estimate of 6% – based on the Ibbotson approach exclusively; and
b) The Wright approach has no impact on the allowed return on equity whatsoever – it has effectively been disregarded.[807]

SFG Consulting shows that the AER effectively has estimated the MRP to be 7.9 per cent[808]. However, this estimate is not used by the AER. Instead the AER compares its proposed return on equity (8.1 per cent) with the Wright estimate of the return on equity where it uses its equity beta range of 0.4 to 0.7 from the previous step of its estimation process despite that it has determined 0.7 to be the appropriate estimate. SFG Consulting concludes:

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[806] SFG Consulting, 2014, *The required return on equity for regulated gas and electricity network businesses*, May, page 4

[807] SFG Consulting, 2015, *The required return on equity: Initial review of the AER draft decisions*, January, page 30

[808] SFG Consulting, 2015, *The required return on equity: Initial review of the AER draft decisions*, January, page 25

That is, having previously concluded (in Step 3 of its estimation approach) that the appropriate equity beta is 0.7, the AER reintroduces an equity beta range of 0.4 to 0.7 for the sole purpose of evaluating the Wright approach (in Step 4 of its estimation approach). The only way the AER can obtain a range for the Wright approach that includes its proposed allowed return on equity is to combine the Wright estimate of MRP with a beta of 0.4, which the AER has already discarded in the previous step of its estimation process. The Wright approach has nothing at all to do with beta – it is used only for estimating the MRP. The AER's own Wright estimate of MRP (7.9%) is unambiguously higher than its proposed estimate of 6.5%. It makes no sense whatsoever for the AER to conclude that its proposed return on equity is consistent with the Wright evidence based on a comparison of:

a) The AER's proposed estimate of MRP (6.5%) multiplied by the AER's proposed estimate of beta (0.7); with
b) The AER's Wright estimate of MRP (7.9%) multiplied by an estimate of beta that the AER has already rejected in a previous step of its estimation process (0.4).

The outcome of such a comparison is that the AER says that it has had regard to the Wright approach, but regard is given to the Wright approach in such a manner as to ensure that it cannot possibly have any effect at all on the allowed return.[809]

ActewAGL Distribution refers to SFG Consulting's report for further details.

Expert report and evidence addressing the AER's use of the Wright approach to estimate the return on equity. • Attachment F1: SFG Consulting: The required return on equity: response to the AER draft decision

ActewAGL Distribution also notes two recent regulatory decisions in Australia that support a prevailing estimate of the MRP as preferable to that applied by the AER.

In November 2014, the Economic Regulation Authority (ERA) in Western Australia handed down a revised decision for estimating the WACC for the regulated railway networks in which the MRP

[809] SFG Consulting, 2015, *The required return on equity: Initial review of the AER draft decisions*, January, page 32 to 33

is estimated as the difference between the estimate of the return on equity for the market and the 'on the day' estimate of the risk free rate. The ERA noted:

> *…for the long term – consistent with the lives of rail infrastructure assets being considered here – the Authority considers that the real return on equity is mean reverting; the unconditional average real return on equity provides a sound basis for the future average outcome in real terms. The corollary is that, on average over the longer term, the MRP will offset changes in the real long term risk free rate. The result is an estimate of the real return on equity for the market that is consistent with longer term averages.*[810]

This approach is consistent with the Wright approach. Using this method, the ERA determined a MRP of 7.9 per cent as the 'current estimate of the long term nominal MRP at the current time'[811].

In December 2014, an Industry Panel reviewing the Independent Competition and Regulatory Commission's 2013 Price Direction in the ACT handed down its draft report. In the report, the Panel stated:

> *…the Panel considers it important to ensure internal consistency within the WACC model as follows:*
>
> - *The average risk-free rate and debt margin should be calculated over a short term and use implied MRPs if a regulator believes that current prices in the market reflect all available relevant information and hence today's prices are the best predictor of the future.*
> - *The average risk-free rate and debt margin should be calculated over a long-term and use long term historical MRPs if a regulator believes that the market will revert to a long-term average. This approach implies that in estimating the WACC, long-term averages are considered the best predictor of the future, and that any discrepancy between short-term and long-term averages is considered temporary.*
>
> *Given the Panel's decision to estimate market based parameters using prevailing rates, its decision to use an implied MRP can be seen as being internally consistent.* [812]

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[810] ERA, 2014, *Review of the method for estimating the Weighted Average Cost of Capital for the Regulated Railway Networks – Revised Draft Decision*, November, pages 85 and 86

[811] ERA, 2014, *Review of the method for estimating the Weighted Average Cost of Capital for the Regulated Railway Networks – Revised Draft Decision*, November, page 98

[812] Industry Panel, 2014, *Review of the Independent Competition and Regulatory Commission's 2013 Price Direction for Regulated Water and Sewerage Services in the ACT, Draft Report*, December, page 175

The Panel determined a MRP of 7.23 per cent based on market conditions as at 31 May 2013.

ActewAGL Distribution considers that both these decisions, despite not taking all information available in the market into account, support its proposal that the prevailing estimate of the MRP is higher than the 6.5 per cent used by the AER as the prevailing risk free rate used in this revised submission is very similar to that used by the ERA and the Industry Panel.

8.3.5.3.2 The AER's view that independent valuation reports should not be used to inform the MRP estimation

Ultimately it is not clear what practical effect, if any, independent valuation reports have on the AER's decision on the return on equity. Due to relegation to an overall return on equity "check" role, they appear to have very little practical impact on the final estimate.

What is clear is that the AER is not using independent valuation reports to inform its estimate of the MRP[813]. ActewAGL Distribution reiterates its position that independent expert reports are a valuable data source and should be relied upon. For its revised submission, based on the expert report from SFG Consulting included in attachment F1, ActewAGL Distribution maintains a weighting of 10 per cent on independent expert valuation reports (that supports a MRP of 6.97 per cent) to inform the MRP.

8.3.5.3.3 The AER's rejection of SFG's construction of the DDM

As identified during the Rate of Return Guideline process, the industry submitted a version of the DDM that SFG Consulting had developed to estimate an industry return on equity that does not assume that all firms grow at the same rate, which is an issue that the AER has identified with its own version of the DDM. However, in the draft decision the AER uses its own construction of the DDM to inform its MRP estimate but did not accept SFG Consulting's construction. The AER:

- considers that SFG Consulting's DDM gives a very high return on equity estimate, equating to an equity beta of 0.94[814] and implausibly high long term dividend growth rate which is larger than the long term GDP growth rate[815];

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[813] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-202

[814] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-190

- prefers the use of overall consensus dividend forecasts versus SFG Consulting's approach that individual analyst forecasts, which adds 'a significant amount of complexity'[816];
- prefers market prices in the DDM versus SFG Consulting's approach that is using target prices[817]; and
- is critical about SFG Consulting's DDM approach to estimate the return on equity at an industry level[818].

SFG Consulting has reviewed the AER's draft decision and in particular the AER's concern that that SFG's model generates a 'very high' return on equity estimate (and implied equity beta). SFG Consulting identifies some fundamental problems with the AER's reasoning and notes:

> *…the AER disregards the SFG DDM evidence on the basis that it is inconsistent with the AER's favoured subset of relevant evidence. If a subset of evidence produces a particular estimate, and any evidence that is inconsistent with that particular estimate is to be rejected, there would appear to be no point evaluating any evidence other than the first subset. This approach would appear to be inconsistent with the Rules requirement to have regard to all relevant evidence. Indeed, the whole point of the requirement to have regard to the whole range of relevant evidence is to ensure that parameters are not estimated on the basis of only a subset of the relevant evidence.*[819]

Moreover, ActewAGL Distribution does not consider that the AER has addressed the weaknesses of its own model's assumptions, as identified above, compared with SFG Consulting's DDM for the industry. ActewAGL Distribution refers for further details to SFG Consulting's report included in attachment F1.

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[815] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-220

[816] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-223 to 3-224

[817] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-225 to 3-226

[818] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-229

[819] SFG Consulting, 2015, *The required return on equity: Initial review of the AER draft decisions*, January, page 40

8.3.5.3.4 The AER's use of survey evidence and conditioning variables

The AER appears to give material weight to survey evidence of the MRP from 2013[820], despite evidence as to the limitations of this evidence (and concerns previously expressed by the Tribunal in this regard that the AER says it acknowledges[821]). As part of its regulatory proposal for the subsequent regulatory period, ActewAGL Distribution submitted an expert report from SFG Consulting that addressed the use of survey evidence in detail (attachment E3 of the regulatory proposal for the subsequent regulatory period). ActewAGL Distribution maintains its reliance on that report.

8.3.5.4 *Assessment of the overall return on equity and ERP*

This section addresses each of the AER's 'cross-checks' on its ERP and return on equity described by the AER as "evaluation of the information set".

8.3.5.4.1 Use of the Wright approach to support the AER's ERP estimate

As noted above, the AER appears to misinterpret or misapply Wright's work. Wright did not develop an alternative implementation of the SL-CAPM for checking of the overall return on equity.

Further, the way in which the AER has developed its ERP range from the Wright approach means that this 'cross-check' will almost certainly support the AER's ERP estimate. The AER derives a wide range of estimates from the Wright approach by using an equity beta range of 0.4 to 0.7 in what it refers to as the 'Wright CAPM'. If the AER had used its point estimate of equity beta of 0.7 in the 'Wright CAPM', this cross-check would not support the AER's ERP estimate as the minimum ERP would be 4.55 per cent (which is the AER's foundation model ERP point estimate) and a maximum of about 6.5 per cent (based on a market return of 12.8 per cent identified as the top end of the range by the AER using the Wright approach[822]).

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[820] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-202

[821] Application by Envestra Ltd (No 2), ACompT 3, Paragraphs 162-163

[822] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-207 to 3-34

As a result, ActewAGL Distribution does not consider that the evidence using the Wright approach supports the AER's ERP estimate.

8.3.5.4.2 Use of the Grant Samuel analysis

The AER presents a wide ERP range from the Grant Samuel report for Envestra. This range encompasses Grant Samuel's "*lower bound*" estimate with no imputation adjustment, as well as the upper bound with Grant Samuel's uplift and an imputation adjustment. The AER notes that "*it is difficult to determine how much of the uplift is attributable to the return on equity*"[823], bit concludes that the Grant Samuel report support 'our foundation model estimate of equity risk premium of 4.55 per cent.

In its revised submission to the AER on 13 January 2015, TransGrid submits a report from Grant Samuel that directly comments on the AER's draft decision and reference to that the Grant Samuel's report is consistent with the AER's ERP estimate of 4.55 per cent. In its report to TransGrid, Grant Samuel states:

> *We have very serious concerns about the validity and/or appropriateness of these statements and we would wish to see them revised in any final decision. In particular:*
>
> - *in relation to the first point it is a clear case of selective "cherry picking" to use our initial calculated CAPM result, with or without dividend imputation adjustments, as supporting the AER's final conclusion when a fundamental aspect of our analysis was to conclude that the calculated CAPM rate was not an appropriate benchmark and understated the realistic required rate of return on equity. The fact that we used similar inputs in the initial CAPM calculation and derived a similar rate as the AER is hardly surprising;*
> - *the AER expresses some doubt as to whether a dividend imputation adjustment should be made to our estimate in order to put it on an "apples for apples" basis with the AER's estimate presumably on the grounds of lack of transparency. It is abundantly clear in our reports that we make no adjustment in our valuations for dividend imputation. Accordingly, a dividend imputation adjustment would be required to ensure comparability with the AER basis of calculation. If a gamma factor is applied, the after tax cash flows will change to allow for the reduced effective tax charge (albeit only after four and a half years in the case of Envestra Limited) and it is therefore necessary to adjust the discount*

[823] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-207, 3-34 and 3-101

rate in order to generate the same net present value (the methodology and quantum of the imputation adjustment is a separate issue);

- *the AER claims that the implied adjusted equity risk premium range in three of the four uplift scenarios referred to by Grant Samuel in Appendix 3 of the Envestra Report justifying its uplift is consistent with its foundation model premium of 4.55%. We do not know how the AER determined this but our calculations indicate that in fact the 4.55% is well in the range in only one of the scenarios, is right at the bottom of the range in one other scenario and is outside the range in the other two;*
- *in our view the final paragraph is misleading. The AER claims that based on our final WACC estimate for Envestra Limited (i.e. adjusted for the uplift), the implied equity risk premium is in the range 4.3-6.2% (again supposedly consistent with its estimate of 4.55%). The arguments underpinning this range are repeated in Figure 3-9. The AER claims the upper end of the range is likely overstated due to its concerns over dividend imputation and the likelihood that some of the uplift should apply to the return on debt. We have stated above that there is a clear need for a dividend imputation adjustment (to ensure comparability with the AER bases of calculation) and we reject the argument that any meaningful portion of the uplift should be attributed to debt. For a start, it is our decision as to where any uplift should be allocated but, in any event, the reasons that were set out in the Envestra Report, if carefully read, do not support the AER's argument. At no stage did we state that we assumed an uplift in risk free rates over time or use this as the basis of the uplift (we only noted the risk of this occurring and referred to other practitioners practices). Moreover, it is obvious that the cost of debt can, at least in theory, be locked in at the specified rate for the ten year duration of the assumption while the cost of equity is a constantly changing variable reflecting contemporaneous market conditions.*

  In fact, we consider that the low end of the range calculated by the AER to be misleading as it assumes no adjustment for dividend imputation and "maximises" the allocation of the uplift to the return on debt (whatever that means). We consider Figure 3-9 to be even more misleading as it presents the bottom of the range with no uplift and no imputation adjustment. We also object to this being described as the "Grant Samuel ERP Range" when it has been subject to a number of adjustments and assumptions by the AER (with which we disagree); and
- *the AER has chosen to completely ignore our statement in the Envestra Report that the appropriate range for the WACC was realistically in the range 6.5% to 8.0%. We selected 6.5-7.0% so as to ensure a more robust conclusion as to "fairness". A more "middle of the road" estimate would arguably be, say, 7.0-7.5% (i.e. an additional 0.5% uplift in the cost of equity).*

Based on this ActewAGL Distribution rejects the AER's reference to Grant Samuel's Envestra report in its draft decision, noting that the AER's ERP estimate rather sits at the bottom in one scenario, is outside Grant Samuel's range in two scenarios and only in the range in one scenario. ActewAGL Distribution includes the entire report in attachment F13.

8.3.5.4.3 ERP estimates from 'other market participants', including practitioners and regulators

The AER refers to an ERP range from market practitioners and other regulators. As it reflects a combination of regulatory decisions and practitioners view, it is a relatively broad range.

ActewAGL Distribution does not consider that other regulatory decisions should be given weight by the AER as a source of evidence in relation to the overall required return on equity. Those decisions are made under different requirements/legislations that may impact the overall ERP. Certainly, these decisions should not be mixed with practitioner evidence under the banner of 'market evidence'.

In relation to the relevant independent valuation reports referred to by the AER[824], it should be noted that:

- the imputation-adjusted ERP in all but two of these reports is at least 5 per cent - well above the ERP determined by the AER (4.55 per cent);
- the imputation-adjusted ERP from the Grant Samuel report for Envestra is quoted as 4.47 per cent. However this appears to be based on the mid-point of Grant Samuel's range, with none of the uplift used by Grant Samuel. As noted above, the appropriate measure of the ERP to be drawn from the Grant Samuel report is the upper bound value, with Grant Samuel's uplift; and
- the only other report with an imputation-adjusted ERP less than 5 per cent is more than ten years old.

8.3.5.4.4 Relevance of past investment outcomes

Whether previously determined rates of return have discouraged investment is irrelevant, given that rates of return in previous periods have been estimated:

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[824] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, pages 3-93 to 3-94, Table 3-20

- with different input parameters (in particular, a higher equity beta); and
- in different market conditions (with higher prevailing risk-free rates).

8.3.5.5 *Summary*

While ActewAGL Distribution maintains its position on relevant return on equity models and relevant evidence in relation to model parameters, ActewAGL Distribution has updated the estimates of model parameters and outputs based on the prevailing conditions applicable to this revised regulatory proposal, and weighting of model outputs has been reconsidered, recognising that no model is superior. In doing this, ActewAGL Distribution has relied on an expert report from SFG Consulting included in attachment F1 to derive return on equity estimates for the four models considered that is consistent with the Rules and the rate of return objective. The revised estimate of the return on equity is shown in Table 8.5.

Table 8.5 ActewAGL Distribution revised return on equity estimate

Component	Value
SL CAPM	9.55%
DDM	10.55%
Fama French three factor model	10.37%
Black CAPM	10.17%
Revised overall return on equity estimate	**10.16%**

The return on equity has been estimated using an averaging period of 20 business days to 19 December 2014.

8.3.5.6 *Averaging period for the return on equity to be used in the final decision*

ActewAGL Distribution maintains its position in relation to the return on equity averaging period provided in the regulatory proposal for the subsequent regulatory period discussed in section 10.5.5.

8.4 Return on debt

8.4.1 Overview

ActewAGL Distribution maintains its proposal that return on debt be based on an immediate transition into a long term averaging period of ten years. As part of this revised regulatory submission, ActewAGL Distribution has used a simple average of RBA and Bloomberg BBB rated curves to estimate the return on debt which is consistent with the AER's draft decision.

ActewAGL Distribution has used the AER's methodology to extrapolate RBA and Bloomberg data back to July 2004[825]. The model calculating the return on debt is included in confidential attachment F11 and is summarised in Table 8.6.

Table 8.6 ActewAGL Distribution revised return on equity estimate

Component	Value
Return on debt using RBA, January 2005 – June 2014	7.99%
Return on debt using Bloomberg, January 2005 – June 2014	7.93%
Revised return on debt estimate	7.96%

8.4.2 Requirements of the Rules and Law

Relevantly clause 6.5.2 of the Rules states:

(h) The return on debt for a regulatory year must be estimated such that it contributes to the achievement of the allowed rate of return objective

(i) The return on debt may be estimated using a methodology which results in either:

(1) the return on debt for each regulatory year in the regulatory control period being the same; or

(2) the return on debt (and consequently the allowed rate of return) being, or potentially being, different for different regulatory years in the regulatory control period.

(l) If the return on debt is to be estimated using a methodology of the type referred to in paragraph (i)(2) then a resulting change to the Distribution Network Service Provider's annual revenue requirement must be effected through the automatic application of a formula that is specified in the distribution determination.

[825] For RBA, ActewAGL Distribution has used the January 2005 observation and applied to the period July 2004 to December 2004 as RBA's data is not available before January 2005. ActewAGL Distribution notes that this (RBA January 2005 value) is considerably lower than the Bloomberg's return on debt value for the July 2004 to December 2004 period. In relation to Bloomberg, ActewAGL Distribution changes source from BFV to BVAL at the start of February 2014, consistent with approximately when Bloomberg introduced its BBB BVAL fair value curve.

In estimating the return on debt, clause 6.5.2(k) of the Rules also requires the AER to have regard to:

- the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity referred to in the allowed rate of return objective;
- the interrelationship between the return on equity and the return on debt;
- the incentives that the return on debt may provide to capital expenditure over the regulatory control period, including as to the timing of any capital expenditure; and
- any impacts (including in relation to the costs of servicing debt across regulatory control periods) on a benchmark efficient entity referred to in the allowed rate of return objective that could arise as a result of changing the methodology that is used to estimate the return on debt from one regulatory control period to the next.

8.4.3 ActewAGL Distribution's proposal

- ActewAGL Distribution proposed its return on debt be calculated in accordance with the approach proposed by the AER in its Guideline, with the exceptions that ActewAGL Distribution proposed:the immediate adoption of the AER's 10 year trailing average portfolio approach (with no transition of the kind proposed by the AER); and
- the use of a credit rating of BBB (rather than BBB+ as proposed by the AER);
- the averaging period for use in calculating the prevailing rate of return on debt in each of the regulatory years 2016/17, 2017/18 and 2018/19 of the regulatory control period be nominated by ActewAGL Distribution prior to the occurrence of that averaging period and not in the regulatory proposal for the subsequent regulatory period (or revised regulatory proposal) or, in the case of the 2017/18 and 2018/19 regulatory years, prior to the commencement of the regulatory control period.

8.4.4 AER draft decision

The AER determines to use a trailing average portfolio approach and to update the return on debt estimate annually.[826]

The AER's draft decision does not accept ActewAGL Distribution's proposal for an immediate transition to a 10 year averaging period and instead implementsd transitional arrangements

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[826] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-102

based on the 'QTC method' (an annual re-pricing of a portion of the national debt portfolio) and a benchmark term of ten years.[827]

The AER concludes that the use of transitional arrangements is consistent with Rules.[828] The AER reasons that, under its transitional arrangements, the allowed return on debt for debt that existed at the start of the 2014-19 is set in a manner similar to the previous on-the-day approach. Therefore, there is no impact on the benchmark entity from changing the return on debt methodology from one regulatory period to the next.

The AER further reasons that commencing the trailing average with a period of transition contributes to the achievement of the rate of return objective because it minimises the potential mismatch between the allowed and actual return on debt of the benchmark efficient entity, while also avoiding windfall gains or losses to service providers or consumers from changing the regulatory approach to the return on debt. For these reasons, the AER concludes, it also provides service providers with a reasonable opportunity to recover at least their efficient debt financing costs.

With respect to minimising the potential mismatch between the allowed return on debt and the actual return on debt of the benchmark efficient entity as it transitions its financing practices, the AER states :

> *…we have investigated the strategies the benchmark efficient entity could have employed to efficiently finance itself under the previous on-the-day approach.*
>
> *We consider an efficient financing practice of the benchmark efficient entity under the on-the-day approach would have been to borrow long term and stagger the borrowing so that only a small proportion of the debt matured each year. We consider the benchmark efficient entity would have combined this practice with interest rate swap contracts to match the risk free rate component of its return on debt to the on-the-day rate.*[829]

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[827] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-102

[828] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-114

[829] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, pages 3-115 to 116

The AER also noted that:

> *A staggered debt portfolio with interest rate swaps is also the financing strategy generally adopted by most private service providers under the on-the-day approach.*[830]

On the basis of its investigation of the strategies the benchmark efficient entity would have employed under the previous on-the day-approach, the AER concludes that applying transitional arrangements minimises the potential mismatch between the risk free rate component of the allowed return on debt and the actual return on debt of the benchmark efficient entity as it transitions its financing practices to the AER's trailing average approach.[831]

While the AER accepts ActewAGL Distribution’s proposed averaging period for the financial years 2014/15 and 2015/16, the AER did not accept ActewAGL Distribution’s proposed approach to the nomination of averaging periods for the financial years 2016/17, 2017/18 and 2018/19.[832]

In estimating the return on debt, the AER used the average of RBA’s extrapolated published 10 year BBB rate bond yields and of Bloomberg’s extrapolated 7 year BBB-rate BVAL curve[833]. Both estimates were annualised.

The AER's draft decision in respect of credit rating is discussed at sub-section 8.2.4 above.

8.4.5 ActewAGL Distribution's response

ActewAGL Distribution accepts that the return on debt estimate will be updated annually.

Consistent with the regulatory proposal for the subsequent regulatory period, ActewAGL Distribution maintains that the return on debt be calculated in accordance with the approach proposed by the AER in its Rate of Return Guideline with the exceptions proposed in that proposal as referred to above at sub-section 8.4.3.

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[830] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-117

[831] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-118

[832] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-157 to 3-160

[833] To extrapolate the 7 year BBB BVAL curve, the AER used the margin between the adjusted 7 year RBA BBB yield estimate and the adjusted 10 year RBA BBB yield estimate.

8.4.5.1 *Immediate adoption of a 10 year trailing average period*

ActewAGL Distribution contends that the establishment of the transitional arrangements proposed by the AER is impermissible because those arrangements result in a return on debt that does not contribute to the achievement to the rate of return objective as required by clause 6.5.2(b) and (h) of the Rules. Put another way, ActewAGL Distribution considers that the transitional arrangements result in a return on debt that is not commensurate with the efficient debt financing costs of the benchmark efficient entity as is required by clause 6.5.2(b) and (h).

ActewAGL Distribution submits that, regardless of the characteristics of the 'benchmark efficient entity', the pre-existing regulatory approach to the estimation of the return on debt is of no relevance to the 'efficient financing costs' referred to in the rate of return objective or, thus, to the content of that rate of return objective.

The term 'efficient financing costs' is properly construed as referring to the costs of capital commensurate with the riskiness of the investment where efficient financing practices are adopted.[834] Those costs are a product of the return required by capital market investors (in the case of the return on debt, debt holders) having regard to the degree of risk consequent upon the characteristics of the benchmark efficient entity.[835]

The financing practices of relevance to the term 'efficient financing costs' do not encompass practices adopted in response to a pre-existing regulatory approach to the estimation of the return on debt notwithstanding whether one of the characteristics of the benchmark efficient entity that informs the degree of risk for which capital market investors require compensation is that that entity is regulated. This is particularly so where the pre-existing regulatory approach does not, indeed may not have been designed to, result in an estimate of the efficient financing costs of the benchmark efficient entity.

Such a construction of the term 'efficient financing costs' is consistent with the objective of the regulatory regime established by the NEL and the Rules, as evinced by the NEO and the RPPs, which is itself concerned with creating incentives for efficiency and mimicking, so far as practicable, the outcomes of a workably competitive market, including in particular by creating

[834] See, for example, AEMC, 2012, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November, pages 43 to 44

[835] See, for example, AEMC, 2012, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November, pages 43 to 44 and 65

incentives for providers to operate and invest in the manner of a firm in a competitive environment.[836]

Construing the term 'efficient financing costs' as encompassing the costs incurred as a consequence of a pre-existing regulatory approach to the estimation of the return on debt would be to effectively define the rate of return objective, being the criterion for selection of the regulatory approach to estimation of the return on debt, by reference to the pre-existing regulatory approach for estimation of the return on debt. Such a construction would be perverse.

In addition, adopting a construction of the rate of return objective that renders that objective a product of the pre-existing regulatory approach, is inconsistent with, and likely to hinder the achievement of, the very policy intent that informed the establishment of the rate of return objective.

In establishing an overall rate of return objective to govern determination of the allowed rate of return, the AEMC was concerned to bring the focus of the rate of return estimate back to the NEO and the RPPs, which, as already noted, are concerned with creating incentives for providers to adopt the practices of a firm in a competitive environment. In particular, the AEMC was concerned to confer on the AER sufficient flexibility to consider alternative methodologies, changing market conditions and new evidence as it emerges, and to adjust or adapt its methodologies if justified.[837] The AEMC reasoned that, if the allowed rate of return is not determined with regard to prevailing market conditions and available evidence, *'it will either be above or below the return that is required by capital market investors at the time of the determination'*.[838]

If, however, the term 'efficient financing costs' is construed as encompassing, such the rate of return objective is defined by reference to, costs incurred as a consequence of pre-existing approaches to determining the allowed rate of return, it would follow that the AER's flexibility to respond to changing market conditions and new evidence, and to adjust or adapt its methodologies, would be constrained by reference to those previous regulatory approaches. This cannot be reconciled with the AEMC's policy intent.

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[836] See, for example, *Application by EnergyAustralia and Others* [2009] ACompT 8 (with Corrigendum), at [78]-[80] and [106].

[837] AEMC, 2012, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November, pages 43 to 44

[838] AEMC, 2012, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November, page 44

It is the AER's trailing average approach that is consistent with an efficient debt financing strategy and, thus, estimates the efficient debt financing costs of the benchmark efficient entity. By contrast, the previous on-the-day approach is not consistent with an efficient debt financing strategy. ActewAGL Distribution reiterates the following findings of CEG in its expert report attached to ActewAGL Distribution's regulatory proposal for the subsequent regulatory period:

> *In its rate of return guideline (Guideline) the AER accepts that, in the long-term, the benchmark efficient debt management strategy for a regulated energy utility will be to have an evenly staggered issuance of 10 year debt. Consistent with this, the AER proposes that, in the long-term, the cost of debt allowance will be set based on a trailing average of the cost of issuing 10 year debt. The AER does not include in its definition of the long-term benchmark efficient debt management strategy any role for the use of interest rate swaps to alter the base interest rate costs that otherwise flow from a trailing average (i.e., a staggered debt issuance program).*
>
> *There is no disagreement between the AER and myself on this definition of the appropriate long-term benchmark efficient debt management strategy.*[839]

Indeed, in the draft decision, the AER concedes that the on-the-day approach was never designed to estimate the efficient debt financing costs of a benchmark efficient entity. The AER relevantly concludes:[840]

> *The on-the-day approach was a regulatory approach we sort [sic] to implement in past regulatory decisions to set the allowed return on debt. It was designed to match the allowed return on debt to prevailing market conditions in the market for funds at the start of each regulatory control period. However, it was not designed to match the costs of any particular viable financing practice for the benchmark efficient entity.*

It follows that the adoption of the trailing average approach (without transition) will result in an estimate of the return on debt that is commensurate with the efficient debt financing costs of the benchmark efficient entity and is, thus, the approach that produces an allowed rate of return that the rate of return objective as required by clause 6.5.2(b) and (h) of the Rules.

The mandatory considerations set out in clause 6.5.2(k) of the Rules do not undermine the primacy of the rate of return objective. This follows from their legal character, being no more

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[839] CEG 2014, *Debt transition consistent with the NER and NEL*, May, page 1

[840] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-115

than mandatory considerations, and is consistent with the AEMC's express policy intent.[841] In any event, regard to those mandatory considerations does not inexorably result in a conclusion that a transitional arrangement should be established in determining the return on debt for ActewAGL Distribution.

The first and fourth of the mandatory considerations set out in clause 6.5.2(k) of the Rules are of potential relevance to the decision whether to establish transitional arrangements in estimating the return on debt for ActewAGL Distribution for the 2014-19 period. These considerations are as follows:

> *(1)* *the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity referred to in the* allowed rate of return objective*;*
>
> *…*
>
> *(4)* *any impacts (including in relation to the costs of servicing debt across* regulatory control periods*) on a benchmark efficient entity referred to in the* allowed rate of return objective *that could arise as a result of changing the methodology that is used to estimate the return on debt from one* regulatory control period *to the next*.

The first of these considerations requires the AER to have regard to the desirability of minimising any difference between the efficient debt financing costs of the service provider in issue and those of the benchmark efficient entity referred to in the rate of return objective. The AEMC envisaged that a consideration of this matter would inform, for example, the AER's determination of the characteristics of the benchmark efficient service provider.[842]

ActewAGL Distribution observes that, as explained in its regulatory proposal for the subsequent regulatory period, ActewAGL Distribution is 100% financed by equity and has no debt financing.[843] It follows that a consideration of ActewAGL Distribution's own efficient debt financing costs does not weigh in favour of establishing transitional arrangements. To the

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[841] AEMC, 2012, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November, page 56, wherein the AEMC observed that 'at no stage [did it] undermin[e] the primacy of the overall allowed rate of return objective', and p. 68.

[842] AEMC, 2012, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November, pages 84 to 85

[843] ActewAGL Distribution, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period, Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), page 282

contrary, as explained in its regulatory proposal for the subsequent regulatory period, such a consideration establishes that no transition is required for ActewAGL Distribution.[844]

The fourth consideration requires a consideration by the AER of the impacts of changes to its method for estimation of the return on debt from one regulatory control period to the next. While the impacts of relevance are those on the benchmark efficient entity and not ActewAGL Distribution, even if the AER were to conclude that those impacts warranted consideration of a transition, clause 6.5.2(k) of the Rules does not authorise it to establish a transition that detracts from the achievement of the rate of return objective. This not only follows from the legal character of clause 6.5.2(k) but was expressly affirmed by the AEMC in establishing that provision as follows:[845]

> *The purpose of the fourth factor is for the regulator to have regard to impacts of changes in the methodology for estimating the return on debt from one regulatory control period to another…*
>
> *It **may** be possible in many circumstances for the method to estimate the return on debt to take such concerns into account in the design of the method…* [emphasis added]

For the reasons already explained, ActewAGL Distribution considers the establishment of the transition proposed by the AER would detract from the achievement of the rate of return objective.

For these reasons, ActewAGL Distribution considers that consideration of the matters set out in clause 6.5.2(k)(1) and (4), on balance, supports a decision not to establish a transitional arrangement in determining its allowed return on debt.

As noted above, the AER concludes that its proposed transitional arrangements are consistent with the Rules' requirements applicable to the return on debt, including in particular by contributing to the achievement of the rate of return objective, because:[846]

- the allowed return on debt for debt that existed at the start of the 2014-19 is set in a manner similar to the previous on-the-day approach, with the consequence that there is

[844] ActewAGL Distribution, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period, Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), pages 280 and 283

[845] AEMC, 2012, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November, page 85

[846] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-114

'minimal' impact on the benchmark entity from changing the return on debt methodology from one regulatory period to the next;

- the transitional arrangements minimise the potential mismatch between the allowed and actual return on debt of the benchmark efficient entity; and
- those arrangements avoid windfall gains or losses to service providers or consumers from changing the regulatory approach to the return on debt.

In reaching this conclusion, the AER does not articulate the manner in which it has construed and applied the relevant Rules' requirements, nor does it articulate why it follows from the matters detailed above that those Rules' requirements (as construed by it) are satisfied.

As a consequence, the nature of its reasons for decision and, thus, the error made by the AER - that is, whether error of law, error of fact or want of reason or some combination of these - are unclear. However, the AER's conclusion cannot be reconciled with the proper construction and application of the Rules' requirements outlined above.

While it is difficult to respond to the AER's reasons for its draft decision to establish a transitional arrangement for estimation of ActewAGL Distribution's return on debt for the reasons already noted, ActewAGL Distribution makes the following observations in response to that reasoning:

- In asserting that its proposed transitional arrangements are consistent with the Rules' requirements applicable to the return on debt because, under its transitional arrangements, the impact on the benchmark efficient entity is 'minimal', the AER disregards the primacy of the rate of return objective in deciding whether to establish transitional arrangements and would appear to accord to the matter set out in clause 6.5.2(k)(4) the character of a decision criterion rather than its true legal character of mandatory consideration;
- In asserting that the transition contributes to the achievement of the rate of return objective because it minimises the potential mismatch between the allowed and actual return on debt of the benchmark efficient entity, the AER would appear to:
    - misconstrue the rate of return objective, in that it construes 'efficient financing costs' as encompassing the actual financing costs incurred, and practices that, acting rationally, would have been adopted, by the benchmark efficient entity in response to a pre-existing regulatory approach that (on its own admission) did not, and was not designed to, estimate a return on debt that achieves the rate of return objective;
- misconstrue the mandatory consideration set out in clause 6.5.2(k)(1) of the Rules, in that, whereas that consideration requires the AER to have regard to the desirability of minimising any difference between the efficient debt financing costs of the service provider in issue (here, ActewAGL Distribution) and those of the benchmark efficient

entity referred to in the rate of return objective, the AER has considered the desirability of minimising any difference between the actual debt financing costs of the benchmark efficient entity and its allowed debt financing costs; and/or

  - disregard the primacy of the rate of return objective and accords to the matter set out in clause 6.5.2(k)(1) the character of a decision criterion rather than its true legal character of mandatory consideration; and

- In asserting that the transition contributes to the achievement of the rate of return objective because it avoids windfall gains or losses to service providers or consumers from changing the regulatory approach to the return on debt, the AER has regard to a matter that has no direct relevance to either the rate of return objective or the mandatory considerations set out in clause 6.5.2(k). To the extent this is permissible, it would also be permissible for the AER to have regard to the absence of any justification for a transitional arrangement for ActewAGL Distribution having regard to its particular circumstances (as was established by CEG in its report accompanying ActewAGL Distribution's regulatory proposal for the subsequent regulatory period) and consideration of this matter would render the decision to establish such an arrangement incorrect and unreasonable.

Consistent with this, ActewAGL Distribution considers that its proposal with an immediate adoption of the 10-year averaging period to determine the return on debt is compliant with the Rules' requirements in that it results in an allowed rate of return that achieves the rate of return objective and such an approach is correct and reasonable having regard to relevant considerations.

CEG report

In response to the draft decision, ActewAGL Distribution also engaged CEG to review the issues raised by the AER in its draft decision in relation to an immediate transition to the trailing average. CEG's report is included in attachment F2. CEG notes:

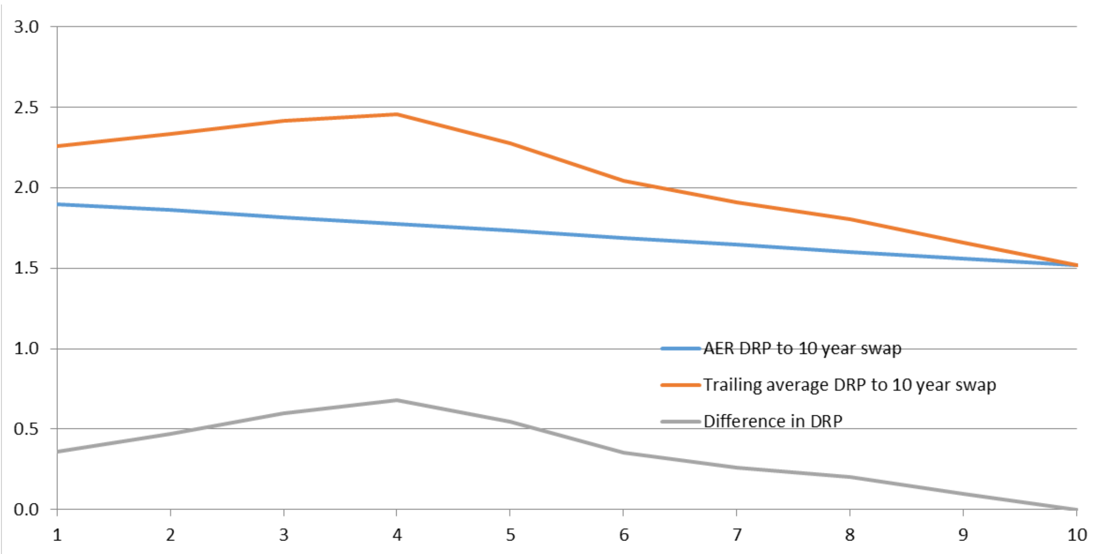
- Under the previous 'on the day' approach, a business who used a swap strategy to try and lock in prevailing interest rates over the regulatory period would have debt costs equal to (the hybrid debt management strategy):
  - the prevailing 5 year swap rate at the beginning of the regulatory period; plus
  - the historical average spread to swap on its 10 year corporate debt issuance; plus
  - transaction costs including transaction costs of swaps (which are not allowed for under the AER's transitional approach).
- However, the AER's return on debt allowance in the previous regulatory period did not reflect any of these components of the return on debt. Also:

- The hybrid debt management strategy could result in the business' cost of debt being less well hedged to the regulatory allowance than adopting the trailing average;
- Under the AER's transitional approach (based on the 'on the day' debt raising strategy), businesses would continue to pay a *trailing average* DRP on its actual costs but will be compensated for the *prevailing* DRP;
- The AER proposed transition undercompensates all businesses regardless of funding strategy (trailing average or hybrid strategy management strategy;

- The simple trailing average is an efficient debt management strategy in the past and the future; and
- Lally's comparison of DRPs is at a point in time and does not establish that the AER's proposed methodology will provide appropriate compensation over the 10 years of transition.

The AER's view that a transition is required to avoid windfall gains is incorrect as the cost of debt will rise above the DRP allowed using the AER's cost of debt methodology as shown in Figure 8.2 since the period prior to the global financial crisis (with low DRP levels) will gradually fall away from the estimate.

Figure 8.2 ActewAGL Distribution's DRP versus trailing average DRP (DRPs measured relative to swaps)



Source: CEG analysis

Specifically, over the next ten year period, the sum of the differences between the trailing average DRP and the allowed DRP will be 3.57%, or an average of 36 basis points per year. This average is higher over the immediate regulatory period, at 68 basis points per year. This does not include the transaction costs of swaps that are implicitly being used. Adding the transaction cost of swaps would increase the difference by even more.

CEG also notes that the DRP and the base (risk free) rate of interest are strongly inversely related – such that when the latter changes, the former changes in the opposite direction. In light of this ActewAGL Distribution considers that the 'on the day' debt management strategy that hedges one component of the cost of debt (i.e., the base risk free rate) while remaining exposed to the DRP, potentially adds additional interest rate risk by removing a natural hedge between the DRP and the risk free rate. Indeed, CEG notes that this happened during the 2009-14 period.

In addition to the above, ActewAGL Distribution notes that under a trailing debt management strategy results in the network always having an incentive to minimise its total cost of debt, not only the DRP component of the cost of debt as is the case under the 'on the day' approach. ActewAGL Distribution considers that a debt management strategy that minimises its total cost of debt must be operating in a manner that is consistent with the NEO.

8.4.5.2 *Nomination of the averaging period 2016-19*

In the draft decision the AER did not accept ActewAGL Distribution's proposal to nominate the averaging period for the 2016/17, 2017/18 and 2018/19 financial years by 30 April before the commencement of respective financial year.

The AER states the following reasons for its determination not to accept ActewAGL Distribution's proposal for the relevant debt averaging periods:

> *…we consider averaging periods should be determined before the regulatory control period commences. We consider this condition to be consistent with a return on debt averaging period that contributes to the achievement of the rate of return objective.*
>
> *Specifically, this condition:*
>
> - *Provides service providers with sufficient flexibility to organise their financing arrangements. For instance, we provide service providers with the flexibility to nominate the length of their averaging periods, which can be between 10 business days and 12 months.*
> - *Provides service providers with sufficient certainty to organise their financing arrangements. Agreeing to averaging periods upfront provides certainty that no matter how interest rates change, we will compensate service providers for the return on debt during that averaging period by reflecting those interest rates in their revenue allowance. This certainty provides service providers with confidence to organise their financing around the averaging periods they nominate.*

- *Results in an unbiased outcome. This is because it requires service providers to nominate their averaging periods in advance.*
- *Assists in updating service providers' return on debt by automatic application of a formula specified in the determination, consistent with the rules. This is because nominating averaging periods before the regulatory control period commences simplifies the annual updating process.*[847]

The first three of the four reasons provided by the AER immediately above do not provide the AER with sufficient basis for preferring that averaging periods should be determined before the regulatory control period commences.[848]

As to the fourth reason provided by the AER, it is not clear to ActewAGL Distribution why the nomination of averaging period before the regulatory control period commences simplifies the annual updating process.[849] However, this is not a relevant consideration as the Rules do not operate to require a DNSP to nominate an averaging period during the regulatory control period (see clauses 6.3.1(c)(3), 6.5.2(l) and S6.1.3(9) and (9A)).

ActewAGL Distribution maintains that its proposal for the relevant debt averaging periods is compliant with the Rules' requirements, as supported by a legal opinion[850] and as such should be accepted by the AER. However, the AER is silent on its view as to whether it considers ActewAGL Distribution's proposal for the relevant debt averaging periods is compliant with the Rules' requirements.

The AER states only that it assessed ActewAGL Distribution's proposed debt averaging periods against the conditions in the Guideline (which it developed so the application of the averaging

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[847] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 CONFIDENTIAL APPENDIX Attachment 3: Rate of return*, November, page I-9

[848] Nor do the Rules contain such a requirement but, in any event, the AER will be able to ensure all averaging periods are known in advance of the commencement of each financial year

[849] It appears the same amount of work is required by both ActewAGL Distribution and the AER, the difference is when that work occurs. In any event, as there is an annual updating process it is not possible for the AER to undertake all of the necessary work as part of its final determination.

[850] ActewAGL Distribution, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period*, *Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), Attachment E17 - Legal opinion of NER compliance of proposal for nomination of averaging period

periods contribute to the achievement of the rate of return objective).[851] In so doing, the AER has undertaken its assessment in a way that is not in accordance with law. The AER is required to apply averaging periods that contribute to the achievement of the allowed rate of return objective. In applying its self-determined conditions the AER has failed to meet this requirement. Further, the AER has not provided reasons why its approach, as opposed to ActewAGL Distribution's proposed approach, contributes to the achievement of the NEO to the greatest degree.[852]

ActewAGL Distribution considers that the AER has oversimplified how the benchmark efficient business would raise debt. It would not years in advance determine when it would raise debt. Accordingly, ActewAGL Distribution maintains that being able to nominate the averaging period closer to the actual debt raising time is important for the benchmark efficient entity to better manage its ability to match its cash needs with funding.

The AER's argument "that no matter how interest rates change, we will compensate service providers for the return on debt during that averaging period"[853] is true, but does not solve the issue that if a network business needs to issue debt earlier than the nominated averaging period (e.g. four years before the event), it will be exposed to significant risk. The AER's approach does not address that issue. ActewAGL Distribution also considers that its proposal to nominate the averaging period ahead of respective financial year will result in an unbiased outcome.

The AER's reasoning outlined above does not suffice to support the selection of the AER's preferred approach to averaging periods. ActewAGL Distribution therefore considers that the AER, in not accepting ActewAGL Distribution's proposal regarding the averaging periods for the 2016/17, 2017/18 and 2018/19 financial years, has made an error of law, incorrectly exercised its discretion in all the circumstances and made a decision that is unreasonable in all the circumstances.

ActewAGL Distribution finally notes that the AER raised concerns that ActewAGL Distribution's proposal "adds further complexity and costs to the administration of regulation"[854]. ActewAGL Distribution understands and accepts that its proposal would add some additional administrative

[851] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 CONFIDENTIAL APPENDIX Attachment 3: Rate of return*, November, page I-7-8

[852] As required by section 16(1)(d) of the Law

[853] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-159

[854] AER, 2014, *Draft Decision ActewAGL distribution determination 2015-16 to 2018-19 CONFIDENTIAL APPENDIX Attachment 3: Rate of return*, November, page I-9

costs that would be minor and inconsequential to both the AER and ActewAGL Distribution. However, these costs would be minimal compared to the costs and risks to both ActewAGL Distribution and its customers should it be required, due to liquidity reasons, to issue debt outside an averaging period (and the return on debt thereafter falls) because the averaging period was determined to take place too far in advance to accurately forecast the business' liquidity position. Therefore, ActewAGL Distribution considers that it is in the long term interest of customers that the averaging period can be nominated closer (by 30 April each year) to the commencement of a financial year so the liquidity requirements of the benchmark efficient entity can be better optimised and, hence, the financing costs minimised.

Nevertheless, in relation to the averaging period to be used for the future financial years beyond 2015/16, in the event that the AER maintains its draft decision not to allow ActewAGL Distribution to nominate these averaging periods by 30 April before the commencement of respective financial year, ActewAGL Distribution proposes the following confidential averaging periods [CIC]:[855]

[redacted]

8.5 Gamma

8.5.1 Overview

Under the Australian taxation system, tax credits (imputation credit) created by an Australian company may be redeemed by domestic shareholders. An imputation credit is created for each dollar of eligible tax paid by companies. Imputation credits are distributed to shareholders through the payment of franked dividends. Imputation credits therefore represent a benefit for domestic shareholders for their investment in the company in addition to dividends (and capital gains).

The Rules require an estimate of "the value of imputation credits" (also referred to as "gamma") as an input to the calculation of the corporate income tax building block. In order to promote the NEO, the estimate of gamma must reflect the value that equity-holders place on imputation

[855] At page I-10 of the Confidential Appendix the AER notes that it would assess alternative averaging periods against the conditions proposed in the Guideline. For the reasons discussed at sub-section above, to do so would be unreasonable.

credits (as opposed to simply their face value or utilisation rate). This is because, although gamma is an input into the corporate income tax calculation, the value adopted for gamma ultimately has a role determining returns for equity-holders. If the value ascribed to imputation credits is higher than the value that equity-holders place on them, the overall return to equity-holders will be less than what is required to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers.

The estimation method that -the AER proposes to adopt will not result in an estimate of gamma that reflects the value equity-holders place on imputation credits. In summary the AER's method involves the following errors:

- the AER's (revised) definition of theta – which seeks to exclude the effect of certain factors on the value of imputation credits – is conceptually incorrect and inconsistent with the requirements of the Rules;

- the AER incorrectly uses equity ownership rates as direct evidence of the value of distributed credits (theta), when in fact equity ownership rates will only indicate the maximum set of investors who ***may*** be eligible to redeem imputation credits and who may therefore place ***some*** value on imputation credits. Theta can be no higher than the equity ownership rate and will in fact be lower due to factors which reduce the value of credits distributed to Australian investors (e.g. the 45-day rule, transaction costs etc.);

- the AER has erred in its interpretation of the equity ownership data – the ranges used by the AER for the equity ownership rate are inconsistent with the evidence in the draft decision;

- the AER uses redemption rates as direct evidence of the value of distributed credits (theta), when in fact redemption rates are no more than an upper bound (or maximum) for this value;

- the AER has erred in concluding that market value studies can reflect factors, such as differential personal taxes and risk, which are not relevant to the task of measuring theta. Market value studies are direct evidence of the value of imputation credits to investors;

- the AER has erred in its interpretation of market value studies. The AER considers market value studies in a very general manner, rather than considering the merits of the particular market value estimate proposed by ActewAGL Distribution. This is an irrational and unreasonable approach to considering the evidence put forward in relation to the market value of imputation credits;

- as well as (correctly) observing that the market-wide distribution rate is 0.7, the AER has also relied on a higher estimate of the distribution rate for listed equity only. Given that data on the distribution rate is available for all equity, it is neither necessary nor appropriate to separately identify a distribution rate for listed equity only based on a limited sample;

- the AER's ultimate conclusion as to the value for gamma is inconsistent with the evidence presented in the draft decision, including the AER's own analysis of the equity ownership rate and redemption rate – these measures show that the AER has overestimated the value of imputation credits.

The correct approach to estimating gamma is as set out in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period. This involves estimating the distribution rate using ATO data and estimating theta based on the value of imputation credits reflected in share price movements (i.e. using dividend drop-off analysis). Combining the observed distribution rate (0.7) with the best estimate of theta from market value studies (0.35) leads to an estimate for gamma of 0.25 as proposed by ActewAGL Distribution in its regulatory proposal for the subsequent regulatory period.

8.5.2 Requirements of the Rules and Law

ActewAGL distribution identified the key aspects of the Rules and NEL relating to gamma in its regulatory proposal for the subsequent regulatory period. In summary:

- Clause 6.5.3 of the Rules requires an estimate of γ (gamma), being "*the value of imputation credits*";
- Clause 6.5.2, which relates to the rate of return, requires consistency between the approaches to estimating the rate of return and the value of imputation credits;
- As with all of its economic regulatory functions and powers, when assessing ActewAGL Distribution's proposal under the Rules and NEL, the AER is required to do so in a manner that will or is likely to contribute to the achievement of the NEO. Further, where there are two or more possible decisions in relation to ActewAGL Distribution's proposal that will or are likely to contribute to the achievement of the NEO, the AER is required to make the decision that the AER is satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree;
- To the extent the AER's decision on the value to be adopted for gamma involves the exercise of a discretion, the AER must take into account the revenue and pricing principles in section 7A of the NEL.[856] The revenue and pricing principles include that a service provider should be provided with a reasonable opportunity to recover at least its

[856] *National Electricity Law*, section 16(2)(a)(i)

efficient costs and 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;

- ActewAGL Distribution considers that it is clear that what is required under the NER is an estimate of the value of imputation credits to investors in the business. This interpretation is consistent with the broader regulatory framework and the task set by the NER to determine total revenue by reference to the various specified building blocks, as well as past regulatory practice, and previous decisions of the Australian Competition Tribunal (Tribunal);
- this is the interpretation that best achieves the NEO, as it ensures that the adjustment for imputation credits in the taxation building block properly reflects the actual value of imputation credits to investors, not merely their notional face value or *potential* value. Accounting for gamma in this way ensures that the overall return received by investors (including the value they ascribe to imputation credits) is sufficient to promote efficient investment in, and use of, infrastructure, for the long-term interests of consumers.

It is in this context that ActweAGL Distribution presents its response to the AER's draft decision and revised proposal in relation to gamma.

8.5.3 ActewAGL Distribution's proposal

ActewAGL Distribution proposed a gamma of 0.25 being a product of:

- a distribution rate of 0.7, in accordance with the AER Guideline; and
- a value of imputation credits to investors who receive them (theta) of 0.35, departing from the AER Guideline for the reasons expressed in the subsequent regulatory proposal.[857]

8.5.4 AER draft decision

The AER's draft decision did not accept ActewAGL Distribution's proposed gamma. The AER determined a gamma of 0.40 based on a distribution rate of 0.7 and an utilisation rate of 0.57.

The AER considered that a reasonable estimate of gamma is within a range of 0.3 to 0.5 because[858]:

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[857] ActewAGL Distribution, 2014, *Regulatory Proposal, 2015-19 Subsequent regulatory control period*, *Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory,* 2 June (resubmitted 10 July), page 293 and Attachments E1 and E2

- The equity ownership approach the AER is placing most reliance on because its expert, Handley, supports this as the most important approach to estimating the utilisation rate, suggests a value of 0.4 and 0.5 when applied to all equity and between 0.3 and 0.5 when applied to listed equity only.
- Evidence from tax statistics suggest the value could be lower than 0.4.
- A value of 0.4 is reasonable in light of the evidence from implied market value studies which produces results both higher and lower than 0.4.

The AER was also assisted in making its draft decision by a new report from Associate Professor John Handley of the University of Melbourne.[859]

8.5.5 ActewAGL Distribution's revised response

ActewAGL Distribution's detailed response to the AER's draft decision is set out in attachment F5.

8.5.6 ActewAGL Distribution's revised proposal on gamma

For the reasons set out in attachment F5, ActwAGL Distribution does not agree with the AER's position on gamma in the draft decision.

ActewAGL Distribtuions maintains its proposal for a gamma of 0.25, combining a distribution rate of 0.7 with a theta estimate of 0.35.

The correct approach to estimating gamma, which is the approach adopted by the ActewAGL Distribution in this revised proposal, is as follows:

- gamma is estimated as the product of the distribution rate and the value of distributed imputation credits (theta), consistent with the requirements of the NER and conventional theory and practice;
- the distribution rate is observed from ATO data, which shows the proportion of imputation credits that are distributed over time. It is widely accepted that this data shows that the economy-wide distribution rate is 0.7;
- theta is the value of distributed imputation credits to investors, consistent with the requirements of the NER, and is estimated as using the best available market value

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[858] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 4: Value of imputation credits*, November, page 4-15

[859] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 4: Value of imputation credits*, November, page 4-11

study. Market value studies indicate the value of imputation credits to investors, as reflected in share price movements. The best estimate of theta from market value studies is 0.35;

- equity ownership rates and credit redemption rates can only be used to indicate the upper bound for theta, and provide a check on the final point estimate – i.e. to confirm that the point estimate is not too high. These measures indicate that the upper bound for theta is 0.43, and thus confirm that the estimate of theta from market value studies is not too high.

ActewAGL Distribution considers that its approach to determining gamma – which is fundamentally based on estimating the value of imputation credits to investors in the business – will better achieve the NEO. This approach ensures that the adjustment for imputation credits in the taxation building block properly reflects the actual value of imputation credits to investors, not merely their notional face value or potential value. Accounting for gamma in this way ensures that the overall return received by investors (including the value they ascribe to imputation credits) is sufficient to promote efficient investment in, and use of, infrastructure, for the long-term interests of consumers.

8.6 Debt raising costs

8.6.1 Requirements of the Rules and Law

There is no specific clause that addresses debt raising costs. However, ActewAGL Distribution considers that the operating expenditure objective, clause 6.5.6 (a), in the Rules is relevant. It requires a DNSP to include the total forecast operating expenditure for the relevant regulatory control period.

Similarly, the Rules (6.5.6 (c)) require that the DNSP must assess 'the costs that a prudent operator would require to achieve the operating expenditure objectives'.

8.6.2 ActewAGL Distribution's proposal

ActewAGL Distribution submitted that there are three components of debt raising costs:

- The cost of bond issuance for the benchmark debt component of the RAB;
- The cost of maintaining a liquidity reserve (to satisfy Standard & Poor's requirements for an investment grade credit rating); and
- The cost associated with securing the issuance of bonds 3 months ahead of the expiry of issued bonds, as required by Standard & Poor's.

Taking these three costs into account, ActewAGL Distribution proposed debt raising costs of 23.4 bp.

8.6.3 AER draft decision

On debt raising costs, the AER accepted ActewAGL Distribution's debt transaction costs included in the regulatory proposal for the subsequent regulatory period and estimated by Incenta Economic Consulting in an expert report for ActewAGL Distribution.

However, the AER did not accept the proposed liquidity costs and three month ahead financing noting that:

> *"PTRMS's timing assumptions already provide adequate compensation for the timing of revenue compared to expenses, to the extent that these costs streams are necessary. Therefore, there is no need for additional allowances to provide liquidity, or to compensate the service provider for the timing of its financing. This is because the PTRM implicitly provides a favourable allowance that exceeds these amounts."*[860]

The AER also points to the fact that a number of service providers (Ausgrid, Endeavour, Essential and Transend) were aware of the additional cost categories submitted by ActewAGL Distribution, but had chosen not to include them in their opex proposals.

8.6.4 ActewAGL Distribution's response

ActewAGL Distribution does not consider that the AER has provided any valid reason to reject its proposal for an liquidity allowance and costs for raising debt before old debt matures. In relation to the timing assumptions of the PTRM, ActewAGL Distribution considers that the Rules do not provide the AER with a choice about whether it should consider liquidity costs and timing costs for raising debt before it matures are already compensated through the formula that is used in the PTRM model. ActewAGL Distribution considers that the Rules instead require the AER to accept operating expenditure if these are efficient costs that a prudent operator would incur.

In relation to the second point, that other businesses have not proposed to be compensated for these costs, ActewAGL Distribution does not consider this being a valid reason. The AER should assess the costs for the benchmark efficient entity. ActewAGL Distribution considers that the evidence put forward in the report from Incenta clearly shows that these are costs that the benchmark efficient entity would incur to comply with its credit rating.

ActewAGL Distribution engaged Incenta to review the AER's arguments which it relied upon to reject ActewAGL Distribution's proposal in respect of two categories of debt raising costs: liquidity costs and three month ahead financing. Incenta's report supports a total debt raising cost of 19.75 bppa. This is based on the following breakdown:

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[860] AER, 2014, *Draft decision ActewAGL distribution determination 2015-16 to 2018-19 Attachment 3: Rate of return*, November, page 3-322

- Direct debt raising costs 9.89 bppa
- Liquidity requirement allowance of 6.32 bppa
- 3 months ahead financing of 3.54 bppa

The details of Incenta's report is included in attachment F3.

8.7 ActewAGL Distribution's revised regulatory proposal for return on capital, gamma, and debt raising costs

ActewAGL Distribution maintains the position proposed in its regulatory proposal for the subsequent regulatory period, as follows:

- a credit rating of BBB.
- a return on equity of 10.16 per cent, based on an equal weighting of four return on equity models.
- a return on debt of 7.96 per cent based on a ten year averaging period and no transition.
- a gamma of 0.25, by combining a distribution rate of 0.7 with a theta estimate of 0.35 (see section 8.5 and attachment F5)
- debt raising costs of 19.75 bppa recognising that the cost for the direct transaction of raising debt (accepted by the AER), liquidity reserve and costs for issuance of bonds 3 months ahead of the expiry of issued bonds, as required by Standard & Poor's.

9 Revenue requirement

9.1 Introduction

This Chapter 9 responds to the AER's draft decision in respect of the annual revenue requirement (ARR) for the 2014-19 period set out in Attachment 1 to its draft decision.

In its draft decision, the AER determines total revenue requirements for the 2014-19 period, reflecting its draft decisions on the various building block costs, of:

- $633.3 million ($ nominal) for ActewAGL Distribution's distribution network, being a reduction of $244.4 million ($ nominal) or 28 per cent compared to ActewAGL Distribution’s proposal; and
- $127.5 million ($ nominal) for ActewAGL Distribution's transmission network, being a reduction of $57.0 million ($ nominal) or 31 per cent compared to ActewAGL Distribution’s proposal.

The AER's draft decision also provides for an adjustment or ‘true-up’ in respect of the difference between the ARRs for the transitional regulatory period for distribution and transmission approved by the AER in its placeholder determination and the notional ARRs for the transitional regulatory period determined in its draft decision. In performing this 'true-up' for the transitional regulatory period, however, the AER makes a modification to the amount of the ARR that it approved in the placeholder determination for the transitional regulatory period for ActewAGL Distribution's distribution network to account for a change in the energy throughput forecast for 2014/15 accepted by the AER as between the placeholder determination and the draft decision.

As ActewAGL Distribution rejects the AER's draft decisions on the building block costs on which its draft decision on the ARRs for the 2014-19 period is based, including in particular the AER's draft decisions on forecast opex, forecast capex, the rate of return and carryover amounts arising from the application of the EBSS in the 2009-14 regulatory control period, it follows that ActewAGL Distribution also rejects the AER's draft decision on those ARRs.

In addition, ActewAGL Distribution does not accept the AER's draft decision on the 'true-up' for the transitional regulatory period for its distribution network, specifically the AER's modification, in performing that 'true-up', to the amount of the ARR for the transitional regulatory period for that distribution network that was approved by the AER in the placeholder determination to account for the change in the energy throughput forecast for 2014/15. ActewAGL Distribution considers that that modification is legally impermissible and that the transitional regulatory period 'true-up' amount for the purposes of clause 11.56.4(h) and (i) is, therefore, $27.7 million ($ nominal) and not $33.7 million as calculated by the AER.

Section 9.5 below discusses these matters in greater detail and sets out ActewAGL Distribution's revised ARRs, total revenue requirements and X factors for the 2014-19 period for its distribution and transmission networks calculated using its revised proposals for the various building block costs set out in other Chapters of this revised regulatory proposal.

9.2 The relevant legal and regulatory framework for the annual revenue requirements

Clause 6.12.1(2)(i) and (11) of the Rules provides that the constituent decisions by the AER on which the distribution determination for ActewAGL Distribution for the subsequent regulatory period is predicated include (amongst others):

- a decision on ActewAGL Distribution's current building block proposal in which the AER either approves or refuses to approve the ARR for ActewAGL Distribution, as set out in the building block proposal, for each regulatory year of the regulatory control period; and
- a decision on the form of the X factor for the purposes of the control mechanisms for standard control services.

Clause 6.4.3 of the Rules provides for the ARR for each regulatory year of a regulatory control period to be determined using a building block approach, under which the constituent building blocks are:[861]

- indexation of the RAB, where the RAB is calculated in accordance with clause 6.5.1 and Schedule 6.2 and the building block comprises a negative adjustment equal to the amount referred to in clause S6.2.3(c)(4) for that year;
- a return on capital for that year calculated in accordance with clause 6.5.2;
- the depreciation for that year calculated in accordance with clause 6.5.5;

[861] For ActewAGL Distribution, the revenue increments and decrements for the 2014-19 period are confined to those arising from the application of the EBSS in the 2009-14 regulatory control period. This is because there was no capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme applicable to ActewAGL Distribution in the 2009-14 regulatory control period, there are no other revenue increments or decrements arising from the application of a control mechanism in that period and ActewAGL Distribution will not earn any unregulated revenue from the use of standard control services assets in the 2014-19 period. The AER accepts that ActewAGL Distribution is not forecast to earn any unregulated revenues for the 2014-19 period from the use of standard control services assets: AER 2014, AER Draft decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014: Attachment 1, p. 1-23.

- the estimated cost of corporate income tax of ActewAGL Distribution for that year determined in accordance with clause 6.5.3;
- the revenue increments or decrements (if any) for that year arising from the application of any efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme as referred to in clauses 6.5.8, 6.5.8A, 6.6.2, 6.6.3 and 6.6.4;
- the other revenue increments and decrements (if any) for that year arising from the application of a control mechanism in the previous regulatory control period;
- the revenue decrements (if any) for that year arising from the use of assets that provide standard control services to provide certain other services as determined by the AER under clause 6.4.4; and
- the forecast opex for that year as accepted or substituted by the AER in accordance with clause 6.5.6.

Clause 6.5.9(a) of the Rules provides that a building block determination is to include the X factor for each control mechanism for each regulatory year of the regulatory control period. Clause 6.5.9(b)(1) and (3) relevantly provides that the X factor:

- must be set by the AER with regard to ActewAGL Distribution's total revenue requirement for the regulatory control period; and
- must conform with whichever of the following requirements is applicable:
  - if the control mechanism relates generally to standard control services - the X factor must be designed to equalise (in terms of net present value) the revenue to be earned by ActewAGL Distribution from the provision of standard control services over the regulatory control period with ActewAGL Distribution's total revenue requirement for the regulatory control period;
  - if there are separate control mechanisms for different standard control services - the X factor for each control mechanism must be designed to equalise (in terms of net present value) the revenue to be earned by ActewAGL Distribution from the provision of standard control services to which the control mechanism relates over the regulatory control period with the portion of its total revenue requirement for the regulatory control period attributable to those services.

Clause 6.5.9(c) provides that there may be different X factors for different regulatory years of the regulatory control period and, if there are 2 or more control mechanisms, for each control mechanism.

Clause 11.56.4(c) of the Rules provides that, for the purposes of making the distribution determination for ActewAGL Distribution for the subsequent regulatory period, the AER must determine:

- the annual revenue requirement for ActewAGL Distribution for each regulatory year of the subsequent regulatory period;
- its total revenue requirement for the SRP; and
- the X factor for each control mechanism for each regulatory year of the subsequent regulatory period,

in accordance with current Chapter 6 (except that clause 6.5.9(b)(2) of current Chapter 6 does not apply to the determination of any X factor) and as if the subsequent regulatory period comprised the transitional regulatory period (as the first regulatory year of the subsequent regulatory period) and all of the regulatory years of the subsequent regulatory period (as the remaining regulatory years of the subsequent regulatory period), and the transitional regulatory period were not a separate regulatory control period. That clause further states, for the avoidance of doubt, that it requires the AER to determine a notional annual revenue requirement and a notional X factor or X factors for the regulatory year that comprises the transitional regulatory period.

Clause 11.56.4(h) and (i) of the Rules provides for the making of an adjustment to the ARRs for one or more regulatory years of the subsequent regulatory periodby reference to the notional ARR for the transitional regulatory period determined by the AER. Specifically, clause 11.56.4(h) provides that ActewAGL Distribution's total revenue requirement for the subsequent regulatory periodmust be fully adjusted for the adjustment amount determined in accordance with paragraph (i) by increasing (where the adjustment amount is negative) or decreasing (where the adjustment amount is positive) the ARR of one or more regulatory years of the subsequent regulatory periodas the AER considers appropriate. Clause 11.56.4(i) provides that, for the purposes of paragraph (h), the adjustment amount is calculated as:

- the amount of the ARR approved by the AER for the transitional regulatory period under clause 11.56.3(b) or (d); less
- the amount of the notional ARR for the transitional regulatory period that is determined under clause 11.56.4(c),

subject to such modifications in relation to that calculation as are set out in a framework and approach paper in respect of a distribution determination for the subsequent regulatory periodand as are necessary by virtue of the application of a price cap or price control, rather than a revenue cap or revenue control, in respect of standard control services.

Clause 11.56.4(j) of the Rules provides that the AER's determination of:

- the amount of the notional ARR for the transitional regulatory period under clause 11.56.4(c) of the Rules; and
- the adjustment amount under clause 11.56.4(i) of the Rules,

are each taken to be constituent decisions for the purposes of clause 6.12.1 of current Chapter 6 of the Rules.

9.3 ActewAGL Distribution's proposal

ActewAGL Distribution's proposed building block costs and resulting ARRs, total revenue requirements, and X factors, are shown in Table 9.1 and Table 9.2 below for distribution and transmission respectively.[862]

Table 9.1. ActewAGL Distribution's proposed ARRs, total revenue requirement and x-factors, distribution 2014–19 ($ million, nominal)

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Return on capital	62.6	66.3	68.8	71.3	73.6	342.6
Regulatory depreciation	27.0	30.6	31.2	32.6	32.7	154.1
Operating expenditure	66.7	66.8	66.7	70.7	74.1	344.9
EBSS carry over amounts	-9.6	-8.5	-1.5	1.9	0.0	-17.7
Tax allowance	9.8	10.4	10.4	11.5	12.1	53.7
Total revenue building block (unsmoothed)	156.4	165.6	175.3	187.9	192.5	877.7
Energy forecast (MWh)	2,736,688	2,729,815	2,761,282	2,790,890	2,803,657	n/a
Revenue yield ($/MWh)	53.0	62.4	64.9	67.5	70.3	n/a
Smoothed revenue requirement	145.2	170.25	179.21	188.5	197.0	880.15
X (%) in CPI–X formula, distribution	**19.59%**	**-14.66%**	**-1.50%**	**-1.50%**	**-1.50%**	**n/a**

[862] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 304-305

Table 9.2 ActewAGL Distribution's proposed revenue requirement and x-factors, transmission 2014–19 ($ million, nominal)

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Return on capital	13.9	14.5	15.7	18.5	20.4	80.0
Regulatory depreciation	4.2	5.0	5.2	5.6	5.8	25.9
Operating expenditure	13.3	13.4	13.4	14.3	14.9	69.3
EBSS carry over amounts	-1.4	-1.2	-0.2	0.3	0.0	-2.6
Tax allowance	1.5	1.6	1.7	2.0	2.2	9.0
Total revenue building block (unsmoothed)	31.4	33.2	35.8	40.8	43.2	184.6
Smoothed revenue requirement	28.1	34.9	37.7	40.6	43.8	185.1
X (%) in CPI–X formula, transmission	**2.02%**	**-21.22%**	**-5.22%**	**-5.22%**	**-5.22%**	**n/a**

For both distribution and transmission, ActewAGL Distribution proposed an X factor in the second year of the 2014-19 period that differs from that proposed for the remaining regulatory years of the subsequent regulatory period to effect the adjustment required by clause 11.56.4(h) and (i) of the Rules in respect of the difference between the ARR and notional ARR for the transitional regulatory period.[863] In respect of that adjustment, ActewAGL Distribution stated as follows in its regulatory proposal for the subsequent regulatory period:[864]

> *Clauses 11.56.4(h) to (i) of the NER states that the subsequent regulatory period must include an adjustment to the total revenue requirement. The adjustment is the difference between the notional revenue requirement for the regulatory year that is the transitional regulatory period and the amount of the annual revenue requirement that was approved by the AER for the transitional period, subject to any modifications set out in a framework and approach paper. No such modifications were set out in the AER's framework and approach papers for ActewAGL Distribution.*

[863] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 304

[864] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 303

The AER's decision on the transitional year was published on 16 April 2014 and allowed $145.16 million for distribution and $28.09 million for transmission to be recovered in 2014/15. This is less than the revenue building block requirement as part of this proposal. ActewAGL Distribution has therefore included an adjustment to be recovered over the remaining four years of the subsequent regulatory period.

The adjustment to revenues has been done by setting the smoothed revenue in the first year so it matches the Transitional Decision's allowance, and a P0 adjustment in the second year so that smoothed revenues from subsequent years make up the shortfall in the first year in NPV terms.

9.4 AER draft decision

In its draft decision, the AER does not accept ActewAGL Distribution's total revenue requirements for the 2014-19 period, including that for the transitional regulatory period.[865] The AER determines total revenue requirements for the 2014-19 period, reflecting its draft decisions on the various building block costs, of:

- $633.3 million ($ nominal) for ActewAGL Distribution's distribution network, being a reduction of $244.4 million ($ nominal) or 28 per cent compared to ActewAGL Distribution's proposal; and
- $127.5 million ($ nominal) for ActewAGL Distribution's transmission network, being a reduction of $57.0 million ($ nominal) or 31 per cent compared to ActewAGL Distribution's proposal.

The AER's draft decision also provides for an adjustment or 'true-up' in respect of the difference between the ARRs for the transitional regulatory period for distribution and transmission approved by the AER in its placeholder determination and the notional ARRs for the transitional regulatory period determined in its draft decision.[866]

In performing this 'true-up' for the transitional regulatory period, the AER makes a modification to the amount of the ARR that was approved by the AER in the placeholder determination for the transitional regulatory period for ActewAGL Distribution's distribution network to account for a

[865] AER 2014, AER Draft decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014: Attachment 1, p. 1-7

[866] AER 2014, AER Draft decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014: Attachment 1, p. 1-7

change in the energy throughput forecast for 2014/15 accepted by the AER as between the placeholder determination and the draft decision.[867]

Whereas in making its placeholder determination, the AER adopted ActewAGL Distribution's energy throughput forecast for its distribution network for the transitional regulatory period of 2736.7GWh (in applying the Rules' requirement[868] that the ARR for the transitional regulatory period be set so as to minimise variations in prices as between the 2009-14 regulatory control period, the transitional regulatory period and the subsequent regulatory period and between the regulatory years of the subsequent regulatory period, and in determining the smoothed revenue requirement for the transitional regulatory period),[869] in its draft decision the AER assesses ActewAGL Distribution's energy throughput forecast for the transitional regulatory period and determines on a different energy throughout forecast for that year. For the purpose of performing the 'true-up' for the transitional regulatory period for ActewAGL Distribution's distribution network, it has sought to 'update' the ARR for the transitional regulatory period approved by the AER in the placeholder determination to reflect its draft decision on that energy throughput forecast.[870]

In particular, the AER derives a 'placeholder revenue' for the transitional regulatory period for ActewAGL Distribution's distribution network of $151.1 million ($ nominal) to be used in performing the 'true-up' in place of the ARR for the transitional regulatory period approved by the AER in the placeholder determination of $145.2 million ($ nominal).[871] This 'placeholder revenue' is, in essence, what the AER considers to be the 'expected revenue' for the transitional regulatory period and was derived by multiplying the approved revenue yield for the transitional regulatory period of $53.0 per MWh (on which the ARR in the placeholder determination was

[867] AER 2014, AER Draft decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014: Overview, p 77. See, in particular, note (a) to Table B-1 and footnote 165

[868] Clause 11.56.3(b).

[869] Placeholder determination, p. 17, footnote 25; AER 2014, AER Draft decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014: Attachment 1, p. 1-13. See also Placeholder determination, p. 29, footnote 46

[870] AER 2014, AER Draft decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014: Overview, p. 77 (see in particular note (a) on Table B-1 and footnote 165) and Attachment 1, p. 1-13 (see in particular footnote 18)

[871] AER 2014, AER Draft decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014: Overview, p. 77 and Attachment 1, p. 1-13

based) by the AER's updated energy forecast for that year.[872] As a consequence, the AER derives a 'true-up' amount for ActewAGL's distribution network of $33.7 million ($ nominal),[873] instead of the 'true-up' amount of $27.7 million ($ nominal) that is derived using the ARR for the transitional regulatory period determined in the placeholder determination of $145.2 million ($ nominal).[874]

The AER further concludes that, for ActewAGL Distribution's distribution network, the placeholder X factor of 19.6 per cent for the transitional regulatory period provides the appropriate base from which to smooth the proposed expected revenues over the subsequent regulatory period.[875]

As a result of its 'true-up' for the transitional regulatory period and the smoothing of the ARRs, the AER's draft decision is to approve total expected revenues (smoothed) for the subsequent regulatory period of $477.1 million and $98.5 million ($ nominal) for ActewAGL Distribution's distribution and transmission networks respectively.[876]

The AER's draft decision on the building block costs, the ARRs, annual expected revenue and X factors for each regulatory year of the 2014-19 period for ActewAGL Distribution's distribution and transmission networks are shown in Table and Table respectively.[877]

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[872] See, for example, AER 2014, AER Draft decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014: Attachment 1, p. 1-7, including in particular footnote 3, p. 1-13, including in particular footnote 18, and p. 1-17, including in particular footnote 21

[873] AER 2014, AER Draft decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014: Overview, p. 77

[874] AER 2014, AER Draft decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014: Attachment 1, p. 1-7, footnote 3

[875] AER, Draft decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014: Attachment 1, p. 1-15

[876] AER, Draft decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014: Attachment 1, p. 1-7

[877] AER 2014, Draft decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014: Attachment 1, p. 1-9

Table 9.3. Revenue requirement and x-factors, distribution 2014–19, AER draft decision

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Return on capital	47.9	49.6	50.2	50.8	51.2	249.7
Regulatory depreciation	27.0	30.3	30.6	32.0	31.9	151.8
Opex	36.8	38.3	40.0	41.7	43.6	200.4
EBSS carry over amounts	0.0	0.0	0.0	0.0	0.0	0.0
Tax allowance	5.8	6.1	5.8	6.7	7.1	31.4
Total revenue building block (unsmoothed)	117.4	124.3	126.7	131.2	133.7	633.3
Adjustment to correct under recovery in transitional year	-33.7					n/a
Energy forecast (MWh)	2,849,471	2,848,637	2,874,024	2,915,538	2,954,598	n/a
Revenue yield ($/MWh)	53.0	38.7	40.3	41.9	43.6	n/a
Smoothed revenue requirement	151.1	110.3	115.8	122.2	128.8	628.3
X (%) in CPI–X formula, distribution	**19.59%**	**28.78%**	**-1.50%**	**-1.50%**	**-1.50%**	**n/a**

Table 9.4. Revenue requirement and x-factors, transmission 2014–19, AER draft decision

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Return on capital	10.6	11.0	11.3	12.2	12.7	57.7
Regulatory depreciation	4.2	4.9	5.1	5.4	5.6	25.2
Opex	7.3	7.7	8.1	8.4	8.7	40.2
EBSS carry over amounts	0.0	0.0	0.0	0.0	0.0	0.0
Tax allowance	0.8	0.8	0.8	1.0	1.0	4.4
Total revenue building block (unsmoothed)	22.9	24.4	25.3	27.0	27.9	127.5
Adjustment to correct under recovery in transitional year	-5.2					
Smoothed revenue requirement	22.9	24.4	25.3	27.0	27.9	126.6
X (%) in CPI–X formula, transmission	**2.02%**	**20.69%**	**-2.50%**	**-2.50%**	**-2.50%**	**n/a**

9.5 ActewAGL Distribution’s response and revised submission

ActewAGL Distribution does not accept the AER’s substantial reductions to its opex and capex forecasts (as detailed in Chapters 3 and 4 of this revised regulatory proposal) or its rate of return (as detailed in Chapter 8 of this revised regulatory proposal). As a consequence, ActewAGL Distribution also rejects the AER's draft decision on its ARRs, total revenue requirements and X factors for the 2014-19 period for its distribution and transmission networks.

ActewAGL Distribution has calculated its revised ARRs, total revenue requirements and X factors for the 2014-19 period for its distribution and transmission networks using its revised proposals for the various building block costs set out in this revised regulatory proposal.

ActewAGL Distribution has also updated its energy forecasts for the 2014-19 period in this revised regulatory proposal, which under an average revenue cap control mechanism affects the calculated X-factor.

ActewAGL Distribution does not accept the AER’s draft decision to change its transitional regulatory period’s decision made in April 2014 and reduce it by $33.7 million for distribution and $5.2 million for transmission.

Furthermore, were the AER to change its transitional decision, ActewAGL Distribution disagrees with the AER’s draft decision to ‘true up’ the smoothed revenue requirement for 2014/15 for its distribution network (the methodology applied on ActewAGL Distribution’s transmission network is acceptable).

Specifically, ActewAGL Distribution does not accept the modification made by the AER, in performing its 'true-up' for the transitional regulatory period for the distribution network, to the amount of the ARR for the transitional regulatory period that was approved by the AER in the placeholder determination for ActewAGL Distribution's distribution network to account for a change in the energy throughput forecast for 2014/15 accepted by the AER as between the placeholder determination and the draft decision.

ActewAGL Distribution submits that the modification in respect of energy throughput made by the AER in its draft decision to the amount of the ARR that was approved for the transitional regulatory period for ActewAGL Distribution's distribution network, and thus its calculation of the 'true-up' adjustment amount for distribution is impermissible under the savings and transitional rules and, hence, not authorised by the Rules. The adjustment amount, calculated in accordance with law, is $27.7 million ($nominal).In attachment F12 , ActewAGL Distribution provides its detailed legal reasoning and analysis in support of these contentions.

ActewAGL Distribution agrees, however, with the AER’s view that the notional X-factor for the transitional regulatory period used in smoothing expected revenues over the subsequent regulatory period should be set at 19.6 per cent as prices for the transitional regulatory period were based on this approved placeholder X-factor. ActewAGL Distribution’s attached PTRMs (attachments H8 and H9) show how ActewAGL Distribution considers that the smoothed revenue should be modelled for the transitional regulatory period (which approach is consistent with the approach adopted in ActewAGL Distribution's regulatory proposal for the subsequent regulatory period).

ActewAGL Distribution's resultant revised proposal on the building block costs, the ARRs and resulting x factors for the 2014-19 period for its distribution and transmission networks are set out in Table 9.5 and Table 9.6 respectively. ActewAGL Distribution’s revised total revenue requirement is $849.1 million ($ nominal) for distribution and $187.0 million ($ nominal) for transmission.

Table 9.5. Revised building block costs, ARRs and x-factors, distribution 2014–19

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Return on capital	61.3	64.9	67.1	69.2	71.1	333.5
Regulatory depreciation	26.8	30.7	31.2	32.8	33.0	154.5
Opex	63.5	64.2	64.1	67.4	70.3	329.5
EBSS carry over amounts	-9.2	-8.1	-1.0	2.3	0.0	-16.1
Tax allowance	8.6	9.2	8.8	10.3	10.6	47.6
Total revenue building block (unsmoothed)	150.9	160.9	170.2	182.0	185.0	848.9
Adjustment to correct under recovery in transitional year	5.75					n/a
Energy forecast (MWh)	2,781,225	2,755,859	2,788,237	2,813,594	2,824,131	n/a
Revenue yield ($/MWh)	53	61	62	64	65	n/a
Smoothed revenue requirement	145.2	167.1	173.3	179.2	184.4	849.1
X (%) in CPI–X formula, distribution	19.59%	-11.52%	0.00%	0.00%	0.00%	**n/a**

Table 9.6. Revised building block costs, ARRs and x-factors, transmission 2014–19

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*	*Total*
Return on capital	13.6	14.3	15.0	16.6	18.3	77.8
Regulatory depreciation	4.2	5.0	5.3	5.7	5.9	26.1
Opex	14.4	14.9	15.0	15.9	16.6	76.7
EBSS carry over amounts	-1.3	-1.2	-0.2	0.3	0.0	-2.3
Tax allowance	1.4	1.5	1.5	1.8	1.9	8.1
Total revenue building block (unsmoothed)	32.2	34.5	36.6	40.3	42.7	186.4
Adjustment to correct under recovery in transitional year	4.12					n/a
Smoothed revenue requirement	$28.1	$36.6	$38.6	$40.8	$43.0	187.0
X (%) in CPI–X formula, transmission	**2.02%**	**-26.98%**	**-3.00%**	**-3.00%**	**-3.00%**	**n/a**

10 Control mechanism and indicative prices

10.1 Introduction

In this Chapter 10 ActewAGL Distribution responds to the AER's draft decision on the control mechanism for standard control services set out in Attachment 14 to its draft decision. ActewAGL Distribution responds to the AER's draft decision on the control mechanisms for alternative control services in Chapter 14 of this revised regulatory proposal.

This Chapter 10 also contains ActewAGL Distribution's revised indicative prices for distribution standard control services (in section 10.6 below). ActewAGL Distribution's revised pricing methodology for transmission standard control services is provided in Chapter 16 of this revised regulatory proposal.

ActewAGL Distribution is content with the following parts of the AER's draft decision:

- that an average revenue cap will apply in the SRP;
- that the average revenue cap for any given regulatory year be calculated using the formula the AER specifies (in section 14.5.5 and Figure 14.1 of the draft decision) plus any adjustment required to move the DUoS and TUoS under/over account to zero;
- the statements as to how ActewAGL Distribution must demonstrate compliance with the control mechanism for standard control services (appendices A and B of the draft decision);
- the method for TUoS under and over recovery (appendix B of the draft decision);
- the method for reporting on jurisdictional scheme amounts (appendix C of the draft decision).

ActewAGL Distribution understands that the AER's B-factor adjustment will also implement the AER's deemed determination pursuant to clause 6.6.1(e) of Transitional Chapter 6 of the Rules in respect of ActewAGL Distribution's application of November 2013 titled Vegetation management cost pass through (Application).

As ActewAGL Distribution rejects the AER's draft decision in respect of the non-establishment of exit fees, for its proposed types 5 and 6 meter transfer service, to recover the residual value of meters when customers switch to alternative providers, it follows that ActewAGL Distribution also rejects the AER's draft decision on the definition of the B factor to account for residual metering asset costs from alternative control exit fees (see section 10.5.2.3 below). Chapter 14 of this revised regulatory proposal addresses these points in detail.

Further, ActewAGL Distribution does not accept that the transitional T factor in the control mechanism formula in the Stage 1 F&A paper is not required (see section 10.5.3 below). See

Chapter 3 in section 3.8 for the reasoning for retention of the T factor. ActewAGL Distribution continues to propose that the annual adjustment for the cost of debt should be included in the control mechanism as a B factor as the draft decision does not address this proposal.

Given the AER's adoption of a consumption forecast that is significantly different to that proposed by ActewAGL Distribution, if the AER maintains its position in the draft decision, ActewAGL Distribution in turn proposes a consumption forecast correction adjustment be included in the B factor in the control mechanism.

Finally, ActewAGL Distribution contends that the AER's draft decision is not in accordance with law in the following respects:

- the specification of the side constraints applying to price movements of each of ActewAGL Distribution's tariff class being part of the draft decision; and
- its modifications to the procedures for assigning customers to tariff classes.

Section 10.5 below discusses these matters in greater detail.

10.2 The relevant legal and regulatory framework for control mechanisms for standard control services

Clause 6.12.1(11), (13), (17), (19) and (20) of the Rules provide that the constituent decisions by the AER on which the distribution determination for ActewAGL Distribution for the SRP is predicated include (amongst others):

- a decision on the form of the control mechanisms (including the X factor) for standard control services (to be in accordance with the relevant framework and approach paper) and on the formulae that give effect to those control mechanisms;
- a decision on how compliance with the relevant control mechanism is to be demonstrated;
- a decision on the procedures for assigning retail customers to tariff classes, or reassigning retail customers from one tariff class to another (including any applicable restrictions);
- a decision on how the DNSP is to report to the AER on its recovery of designated pricing proposal charges for each regulatory year of the regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges;
- a decision on how the DNSP is to report to the AER on its recovery of jurisdictional scheme amounts for each regulatory year of the regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those amounts. A decision must be made in relation to each jurisdictional

scheme under which the DNSP has jurisdictional scheme obligations at the time the decision is made.

Clause 6.2.5(a) of the Rules provides that a distribution determination is to impose controls over the prices of direct control services, the revenue to be derived from direct control services or both. Clause 6.2.5(b) provides that the control mechanism may consist of a schedule of fixed prices, caps on the prices of individual services, caps on the revenue to be derived from a particular combination of services, tariff basket price control, revenue yield control or a combination of any of these.

Clause 6.2.5(c) of the Rules provides that, in deciding on a control mechanism for standard control services, the AER must have regard to:

- the need for efficient tariff structures;
- the possible effects of the control mechanism on administrative costs of the AER, ActewAGL Distribution and users or potential users;
- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination;
- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and
- any other relevant factor.

Clause 6.2.6(a) of the Rules provides that the control mechanism for standard control services must be of the prospective CPI minus X form, or some incentive-based variant of the prospective CPI minus X form, in accordance with Part C of the Rules.

Clause 11.56.4(b) to (f) of the Rules provides for the application of specified provisions of current Chapter 6 of the Rules on the basis that the TRP is to be treated as either the last regulatory year of the 2009-14 regulatory control period or the first regulatory year of the SRP. Clause 11.56.4(g), in turn, provides that nothing in clause 11.56.4 has the effect of actually rendering the TRP as the first regulatory year of the SRP and, except for the purposes of the application of paragraphs (b) to (f) in accordance with their terms, the TRP must be treated as a regulatory control period that is separate to the SRP.

The provisions of current Chapter 6 set out above are not referred to in paragraphs (b) to (f) of clause 11.56.4. It follows that the AER's constituent decisions on the control mechanism for standard control services, the formulae for that control mechanism and how compliance with that control mechanism is to be demonstrated apply only in the SRP.[878]

Clause 6.12.3(c) and (d) of the Rules provides that:

- the form of the control mechanisms must be as set out in the relevant framework and approach paper; and
- the formulae that give effect to those control mechanisms must be as set out in the relevant framework and approach paper unless the AER considers that unforeseen circumstances justify departing from the formulae as set out in that paper.

Clause 6.8.1(b)(1)(i) and (2)(ii) of the Rules relevantly provides that a framework and approach paper that applies in respect of a distribution determination must set out the AER's decision, for the purposes of that determination, on the form (or forms) of the control mechanisms and the AER's proposed approach to the formulae that give effect to those control mechanisms. Clause 11.56.4(l) of the Rules provides that the AER must make the framework and approach paper(s) that apply in respect of a distribution determination for ActewAGL Distribution for the SRP in two stages, with the matters referred to here to be addressed in the 'Stage 1 F&A Paper'.

In its Stage 1 framework and approach paper published in March 2013 (Stage 1 F&A Paper), the AER decided to apply an average revenue cap form of control to ActewAGL Distribution's standard control services in the SRP and proposed to apply the following formulae to standard control services:[879]

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[878] Clause 11.56.3(a)(5) of the Rules required the distribution determination made by the AER for ActewAGL Distribution for the TRP to specify the same control mechanisms for standard control services as those which were decided for the distribution determination for ActewAGL Distribution for the 2009-14 regulatory control period, except to the extent the framework and approach paper that is published in respect of the SRP for ActewAGL Distribution provides otherwise in accordance with clause 11.56.3(h)(2) of the Rules, in which case the relevant control mechanisms must be as set out in that framework and approach paper. Clause 11.56.3(h)(2) provides that a framework and approach paper that is published in respect of the SRP for ActewAGL Distribution may specify in relation to the distribution determination for ActewAGL Distribution for the TRP, the form of, and formulae to give effect to, the control mechanism for distribution services (which must be the same as the form and formulae that are specified in the SRP by any framework and approach paper) where that paper specifies a classification for distribution services for the TRP that is different to that decided for the distribution determination for ActewAGL Distribution for the 2009-14 regulatory control period.

[879] AER 2013, *Stage 1 Framework and approach paper ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, March, pp. 28 and 37-38

$$\text{(1)}\quad MAAR_t \geq \frac{(\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t} q_{ij}^{t-2})}{kWhtransported_{t-2}}$$ i=1,...,n and j=1,...,m and t=1,...,5

$$\text{(2)}\quad MAAR_t = AAR_t + \frac{(I_t + T_t + B_t)}{kWhtransported_{t^*}}$$

$$\text{(3)}\quad AAR_t = AAR_{t-1}(1 + CPI_t)(1 - X_t)$$

The B_t term is defined in the Stage 1 F&A Paper, for the purposes of the above formulae, as "the sum of annual adjustments in year t. To be decided in the final decision". The T_t term is defined as "the sum of transitional adjustments in year t. To be decided in the final decision".[880]

There was little discussion or explanation of the AER's specification of the proposed formulae for standard control services in the Stage 1 F&A Paper. In its discussion paper on the formulae for the control mechanisms for NSW and ACT DNSPs for the TRP and SRP published by the AER for the purpose of consulting on the proposed formulae, however, the AER observed that:[881]

> *Adjustments made for incentive schemes and annual/transitional adjustments are set out in generic form to allow for future specification.*

10.3 ActewAGL Distribution's proposal

In its regulatory proposal for the SRP, ActewAGL Distribution:

- acknowledged that an average revenue cap would apply to standard control services, as specified by the AER in the Stage 1 F&A paper;[882]
- accepted the formulae for standard control services specified by the AER in the Stage 1 F&A Paper without revision;[883]

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[880] AER 2013, *Stage 1 Framework and approach paper ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, March, pp. 37-38

[881] AER 2013, *Discussion paper Formulae for control mechanisms - Revised: Matters relevant to the framework and approach for NSW and ACT DNSPs 2014-19*, February, p. 10

[882] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, June (resubmitted 10 July 2014), p. 308

- proposed that the annual adjustment for the cost of debt (as discussed in Chapter 10 of the regulatory proposal) should be included in the control mechanism as a B factor;[884]
- proposed an approach to demonstrating compliance with the control mechanism that is consistent with the formulae set out in the AER's Stage 1 F&A Paper;[885]
- proposed that the method for reporting on recovery of designated pricing proposal charges should be the same as that which applied in the 2009-14 regulatory control period;[886]
- proposed a method to be applied for the recovery of jurisdictional scheme amounts;[887] and
- proposed that the procedures for assigning customers to tariff classes should be the same as those applying in the 2009-14 regulatory control period and the TRP.[888]

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[883] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, June (resubmitted 10 July 2014), p. 309

[884] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, June (resubmitted 10 July 2014), p. 309

[885] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June (resubmitted 10 July 2014), pp. 309-310

[886] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, June (resubmitted 10 July 2014), pp. 309-310

[887] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, June (resubmitted 10 July 2014), pp. 311-313

[888] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, June (resubmitted 10 July 2014), p. 313

10.4 AER draft decision

In the draft decision, the AER:

- confirms that an average revenue cap will apply in the SRP, as specified in the Stage 1 F&A Paper;[889]
- states that the average revenue cap for any given regulatory year is the average annual revenue requirement (AARR) (for distribution services) plus the maximum average allowable revenue (MAAR) (for transmission services) for that regulatory year (calculated using the formula it specifies in section 14.5.5 of the draft decision) plus any adjustment required to move the DUoS and TUoS under/over account to zero;
- purports to specify the side constraints applying to price movements of each of ActewAGL Distribution's tariff class by way of the formulae set out in figure 14.2 of the draft decision;
- determined that the transitional T factor in the control mechanism formula in the Stage 1 F&A paper is not required for the reasons it sets out in Attachment 1 to the draft decision;[890]
- defined the B factor to account for approved pass through amounts, and residual metering asset costs from alternative control exit fees, with the latter subject to tolerance limits;
- states that ActewAGL Distribution must demonstrate compliance with the control mechanism for standard control services in accordance with appendices A and B of Attachment 14 to the draft decision. Appendix A also details how ActewAGL Distribution will report to the AER on the recovery of designated pricing proposal charges (described therein as DUoS unders and overs account);
- states that ActewAGL Distribution must submit, in its annual pricing proposal, a record of the amount of revenues recovered from TUoS charges and associated payments (as part of the relevant designated pricing proposal charges) in accordance with appendix B

[889] ActewAGL Distribution notes that the AER incorrectly refers to the control mechanism as a revenue cap in a few places in the Draft Decision – see for example: AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 14*, November, p. 14-7

[890] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 14*, November, p. 14-9

of Attachment 14 to the draft decision. The AER adopts the method for TUoS under and over recovery as proposed by ActewAGL Distribution;[891]

- Approved ActewAGL Distribution's proposed method for reporting on jurisdictional scheme amounts (to account for under or over recovery of those amounts) in accordance with appendix C of Attachment 14 to the draft decision.[892]

The AER determines not to accept ActewAGL Distribution's proposal in respect of assigning retail customers to tariff classes (or reassigning them from one class to another) and instead determines the procedures in appendix D of Attachment 14 to the draft decision are to apply.

The AER does not address the part of ActewAGL Distribution's proposal in respect of the annual adjustment for the cost of debt to be included in the control mechanism as a B factor.

The AER notes that the Stage 1 F&A Paper deliberately set out a generic formula to give effect to the control mechanism for standard control services as the control formula would be completed in the final distribution determination. The draft decision clarifies the AER's position regarding the control formula and its respective parameters.[893]

The AER confirms ActewAGL Distribution's acceptance of the AER's draft decision in respect of STPIS to adjust the AARR by the S-factor.[894]

10.5 ActewAGL Distribution's response and revised regulatory proposal

ActewAGL Distribution does not accept the following parts of the draft decision:

- the specification of the side constraints applying to price movements of each of ActewAGL Distribution's tariff class being part of the draft decision (see section 10.5.1 below);

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[891] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 14*, November, p. 14-11

[892] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 14*, November, p. 14-11

[893] AER 2014, *Draft decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 14*, November, p. 14-8

[894] AER 2014, *Draft decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 14*, November, p. 14-8 to 14-9

- that the transitional T factor in the control mechanism formula in the Stage 1 F&A paper is not required (see section 10.5.3 below);
- the definition of the B factor to account for residual metering asset costs from alternative control exit fees (section 10.5.2.3 below);
- the modifications to the procedures for assigning customers to tariff classes (see section 10.5.4 below).

Each of these aspects of the AER's draft decision is discussed in turn below.

ActewAGL Distribution also seeks confirmation that its understanding of the B factor adjustment is correct (see section 10.5.2.2 below).

10.5.1 Side constraints

In the Draft Decision, the AER states that ActewAGL Distribution will be required to demonstrate in its annual pricing proposal that proposed DUoS prices for the next year (t) will meet the following side constraints formula (expressed in percentage terms) for each tariff class:[895]

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

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

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

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

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

$$\Delta CPI_t = [\frac{CPI_{Mar,t-2} + CPI_{Jun,t-2} + CPI_{Sep,t-1} + CPI_{Dec,t-1}}{CPI_{Mar,t-3} + CPI_{Jun,t-3} + CPI_{Sep,t-2} + CPI_{Dec,t-2}}] - 1$$

[895] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 14*, November, p. 14-13.

CPI means the all groups index number for the weighted average of eight capital cities as published by the ABS, or if the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best estimate of the index.

X_t the smoothing factor determined in accordance with the PTRM as approved in the AER's final decision, and annually revised for the return on debt update in accordance with the formula specified in the rate of return attachment calculated for the relevant year

PT_t is an annual adjustment factor that reflects the pass through amounts approved by the AER with respect to regulatory year t

S_t is the STPIS factor sum of the raw S-factors for all reliability of supply and customer service parameters (as applicable) to be applied in year t. S_t for 2015 and 2016 are set at zero.

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

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

As reflected in section 10.2 above, the relevant constituent decisions that are the decisions to be made in the Draft Decision in Attachment 14 centre on the control mechanism. Side constraints do not form part of the control mechanism. Further, the AER is not required to make a constituent decision in respect of side constraints. As the AER points out in its draft decision, side constraints form part of the annual pricing proposal process, not the Determination process.[896] The inclusion of formulae for the side constraints is therefore impermissible and the relevant part of the draft decision is not in accordance with law. Accordingly, the final decision should not include formulae for the side constraints.

If, contrary to the above, the AER includes the formulae for the side constraints in its final decision then such formulae must merely replicate the requirement of the Rules in clause 6.18.6. The AER should also make clear when it is referring to designated pricing proposal charges.

[896] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, p. 14-11 and 14-13

10.5.2 The B factor adjustment

10.5.2.1 *Adjustments for the annual cost of debt*

In the draft decision the AER has not addressed ActewAGL Distribution's proposal that the annual adjustment for the cost of debt should be included in the control mechanism as a B factor adjustment.[897]

ActewAGL Distribution maintains its proposal on this adjustment and repeats its contentions set out in its regulatory proposal for the SRP.[898]

10.5.2.2 *Recovery of approved cost pass through amounts*

ActewAGL Distribution agrees with the draft decision that approved cost pass through amounts should be recovered through a B factor adjustment, subject to the following comments.

ActewAGL Distribution understands that the AER's B factor adjustment will also implement the AER's deemed determination pursuant to clause 6.6.1(e) of Transitional Chapter 6 of the Rules in respect of ActewAGL Distribution's Application.[899] However, the formulae does not make this clear, in particular as item 2 makes reference to a B_t term but the explanatory definitions refer only to a B_{t+1} term.

ActewAGL Distribution understands that the AER is agreeable to the pass through to distribution network users of the approved pass through amount in full, namely $2,193,438.70 ($2012/13), in the 2015/16 regulatory year.[900] ActewAGL Distribution understands that this will be achieved

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[897] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 309

[898] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), Chapter 10, p. 306

[899] The AER agreed that it is taken to have accepted ActewAGL Distribution's Application and that the manner in which the AER would give effect to the deemed determination would be agreed. To facilitate that agreement ActewAGL Distribution's provided its proposal for the AER's consideration on 14 October 2014, see: ActewAGL Distribution 2014, Letter to C Pattas of the AER from S Devlin of ActewAGL Distribution, 14 October 2014 (Attachment G21).

[900] ActewAGL Distribution 2014, Letter to C Pattas of the AER from S Devlin of ActewAGL Distribution, 14 October 2014

through the AER's constituent decision on the formulae to give effect to the control mechanism for standard control services to be made in the distribution determination for the SRP.[901]

10.5.2.3 *Recovery of residual metering asset costs*

As set out in Chapter 14 of this revised regulatory proposal, ActewAGL Distribution repeats its contention that the AER's classification of the recovery of residual metering capital costs as a standard control service and proposed use of the B_t term in the formulae for the control mechanism for standard control services for *'moving residual capital costs back into [the] standard control services RAB'* is legally impermissible, constitutes an incorrect exercise of discretion and an unreasonable decision in all the circumstances (see section 14.3 for the reasons for this view).

While ActewAGL Distribution considers that the NEO preferable decision is to establish exit fees, for its proposed types 5 and 6 meter transfer service, to recover the residual value of meters when customers switch to alternative providers, ActewAGL Distribution considers that the following modifications to the AER's proposed B factor adjustment are necessary if the AER maintains its draft decision so as to address the risk that would otherwise exist that the tolerance limits would operate to preclude ActewAGL Distribution from recovering the residual capital costs of stranded meters:

- residual meter values should be recovered via network charges from the start of the 2015-19 period, rather than progressively from 1 July 2017 (as under the AER's draft decision);
- the residual value of all metering assets in ActewAGL Distribution's metering RAB should be divided by four and recovered in the B factor in the formulae for the standard control services control mechanism over the 4 years of the SRP; and,
- no tolerance limits should apply to the annual adjustment.

10.5.2.4 *Adjustments for differences between forecast and actual consumption*

In its regulatory proposal for the SRP ActewAGL Distribution noted that the uncertainty surrounding future electricity consumption is greater now than it has been in the past.[902] The

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[901] ActewAGL Distribution proposed this be done by the AER defining the B_t term such that it provides for the recovery of the deemed approved pass through amount by defining year t as the 2015/16 regulatory year, to include approved pass through amounts relating to regulatory year t-1 (i.e. 2014/15) determined by the AER in accordance with clause 6.6.1 of Transitional Chapter 6 but not recovered in that regulatory year t-1 adjusted for the time cost of money, see: ActewAGL Distribution 2014, Letter to C Pattas of the AER from S Devlin of ActewAGL Distribution, 14 October 2014

high degree of uncertainty is evident in the forecasts for the 2015-19 regulatory period. In the draft decision the AER has adopted a forecast that is significantly different to ActewAGL Distribution's proposal.[903]

The potential for significant differences between forecast and actual consumption means that ActewAGL Distribution's actual revenues may differ significantly from the revenues necessary to recover efficient costs.

Given the AER's adoption of a forecast that is significantly different to that proposed by ActewAGL Distribution, if the AER maintains its position in the Draft Decision, ActewAGL Distribution in turn proposes a consumption forecast correction adjustment be included in the B factor. This adjustment is needed to manage the risk of significant under- or over-recovery of revenue relative to efficient cost, given the significant uncertainty about future consumption.

The proposed adjustment contributes towards achieving the NEO, since a situation in which revenues are materially insufficient to cover efficient costs would hinder the promotion of efficient investment and operation of the ACT network. The likelihood of such under-recovery and its impact on revenue are material.

The inherent uncertainty with regard to consumption forecasting over a four year period is demonstrated by the difference between 2013/14 actual consumption in the NEM and the medium forecast prepared by AEMO in June 2012, just 12 months prior to the start of 2013/14. Actual consumption was around 5 per cent lower than the forecast.[904] If the same variance were to occur with respect to the forecasts in this distribution determination, the revenue under-recovery would be $33 million ($2014/15).

Similarly, significant over-recovery of revenue relative to efficient cost would not be in the interest of consumers. Additional administrative costs arising from application of the mechanism are small and outweighed by these benefits. ActewAGL Distribution would continue to bear and manage consumption forecasting risk, with only extreme outcomes subject to adjustment.

** ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 108. See for example the analysis and conclusions in AEMC 2013, *Consideration of differences in actual compared to forecast demand in network regulation*, Advice to SCER, April, pp 51-53.

[903] This is illustrated in Figure 5.3 in Chapter 5 of this revised regulatory proposal.

[904] AEMO 2012, National electricity forecasting report for the National Electricity Market (NEM), 29 June. and AEMO 2014, National electricity forecasting report update for the National Electricity Market (NEM), 17 December.

ActewAGL Distribution's proposed consumption forecast correction adjustment would apply only in limited circumstances. AAD proposes that a correction adjustment be triggered in year *t* if electricity consumption in year *t*-2 exceed or fall short of the electricity consumption forecast for year *t*-2 by more than a deadband threshold of ±2 per cent of the electricity consumption forecast for year *t*-2. The amount of the adjustment to be included in the B factor for year *t* would be equal to the difference between the threshold described above and electricity consumption in year *t*-2, multiplied by $MAAR_{t-2}$ and indexed to year *t* using the weighted average cost of capital. ActewAGL Distribution proposes that this correction adjustment apply only to consumption in the final three years of the regulatory control period (2016/17 to 2018/19). The first year in which an adjustment could potentially be made is 2018/19 for consumption in 2016/17.

Table 10.1: Proposed correction mechanism deadband

Year	2014/15	2015/16	2016/17	2017/18	2018/19
Deadband (% of electricity sales forecast)	No correction	No correction	2	2	2

10.5.3 The T factor adjustment

In the draft decision the AER states:

> *We included a transitional adjustment parameter in our control formula to account for the difference in the notional revenue for the 2014-15 regulatory year established in this decision and the placeholder revenue in our transitional decision for NSW and ACT. We consider that a transitional adjustment parameter is no longer required as we have taken into account this difference as part of the true-up in establishing the smoothed total revenues over the 2015-19 period for this decision.*[905]

ActewAGL Distribution notes that in the Stage 1 F&A paper the AER only broadly defined the T factor as:

> *T is the sum of transitional adjustments in year t. To be decided in the final decision*[906]

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[905] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 14* , November, p. 14-9

[906] AER 2013, *Stage 1 Framework and approach paper ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, March, p. 38

ActewAGL Distribution proposes that the T factor be used to implement a transitional path to the opex allowance determined by the AER, if the AER retains its draft decision to reject ActewAGL Distribution's proposed opex. Details are provided in section 3.8 of chapter 3.

10.5.4 Assigning or reassigning retail customers to tariff classes

The AER states that it did not approve ActewAGL Distribution's proposal because its proposed procedures require minor amendments to allow for a more effective system of assessment and review. In so concluding, the AER has acknowledged that the proposed system is effective yet the AER purports to make a decision that would result in the system being more effective. However, the AER's distribution determination need only contain an effective system (see Clause 6.18.4(b)). As the AER has determined that ActewAGL Distribution's proposal meets this requirement the AER is not permitted to make changes to it and must accept the system as proposed. The AER's proposed modification is therefore not in accordance with law. Accordingly, ActewAGL Distribution maintains its proposal in respect of its system of assessment and review, and contends that the AER should accept that proposal in the final decision.

10.6 Indicative standard control services prices

Indicative distribution use-of-system (DUoS) charges for the subsequent regulatory period are shown in Table 10.1 below. The 2014/15 prices are actual prices that the AER has approved.

In the first year of the subsequent regulatory period (2015/16), distribution prices have been increased to recover an X factor of -11.52 per cent and forecast CPI of 2.50 per cent. In the final 3 years of the period, DUoS prices stay stable in real terms with a 0 per cent X factor and rise in nominal terms with the inflation forecast at 2.50 per cent per annum. The relatively high X factor in 2015/16, compared with the following 3 years, reflects in part the need to recover the additional revenue requirement not recovered in 2014/15 under the AER's placeholder determination.

The actual DUoS prices will be approved each year through the AER's annual network pricing approval process. The approved DUoS prices will depart from the indicative prices due to variations in inflation, the number of customers, demand and energy consumption.

Table 10.1 Indicative distribution use-of-system charges 2014/15 to 2018/19 (excluding GST)

Code	*Description*	*Unit*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
10	**Residential Basic Network**						
	Network access charge	cents/day	23.16	24.72	25.34	25.97	26.62
	Energy consumption	cents/kWh	4.43	3.94	4.04	4.14	4.24
15	**Residential TOU Network**						
	Network access charge	cents/day	23.16	24.72	25.34	25.97	26.62

Code	Description	Unit	2014/15	2015/16	2016/17	2017/18	2018/19
	Energy consumption at max times	cents/kWh	7.87	8.91	9.13	9.36	9.59
	Energy consumption at mid times	cents/kWh	4.84	5.33	5.47	5.60	5.75
	Energy consumption at economy times	cents/kWh	3.30	3.56	3.64	3.73	3.83
20	**Residential 5000 Network**						
	Network access charge	cents/day	44.36	45.92	47.07	48.25	49.45
	Energy consumption for the first 60 kWh per day	cents/kWh	2.97	3.66	3.75	3.84	3.94
	Energy consumption above 60 kWh per day	cents/kWh	4.43	3.94	4.04	4.14	4.24
30	**Residential with Heat Pump Network**						
	Network access charge	cents/day	87.06	88.62	90.84	93.11	95.43
	Energy consumption for the first 165 kWh per day	cents/kWh	1.63	2.24	2.30	2.36	2.42
	Energy consumption above 165 kWh per day	cents/kWh	4.43	3.94	4.04	4.14	4.24
40	**General Network**						
	Network access charge	cents/day	42.67	44.43	45.54	46.68	47.85
	Energy consumption for the first 330 kWh per day	cents/kWh	8.34	8.42	8.63	8.85	9.07
	Energy consumption above 330 kWh per day	cents/kWh	10.57	12.01	12.31	12.61	12.93
60	**Off-Peak (1) Night Network**						
	Energy consumption	cents/kWh	0.10	0.10	0.10	0.10	0.11
70	**Off-Peak (3) Day & Night Network**						
	Energy consumption	cents/kWh	0.23	0.23	0.24	0.25	0.25
80	**Streetlighting Network**						
	Network access charge	cents/day	43.00	45.00	46.13	47.28	48.46
	Energy consumption	cents/kWh	6.19	6.85	7.02	7.19	7.37
90	**General TOU Network**						
	Network access charge	cents/day	42.67	44.43	45.54	46.68	47.85
	Energy consumption at business times	cents/kWh	14.63	17.05	17.48	17.91	18.36

Code	Description	Unit	2014/15	2015/16	2016/17	2017/18	2018/19
	Energy consumption at evening times	cents/kWh	7.21	8.05	8.25	8.46	8.67
	Energy consumption at off-peak times	cents/kWh	3.34	3.77	3.86	3.96	4.06
Low voltage time of use demand network							
101	**LV TOU kVA Demand Network**						
	Network access charge per connection point	cents/day	50.00	53.76	55.10	56.48	57.89
	Maximum demand charge	c/kVA/day	34.31	39.90	40.90	41.92	42.97
	Energy consumption at business times	cents/kWh	2.74	4.70	4.82	4.94	5.06
	Energy consumption at evening times	cents/kWh	2.08	3.08	3.16	3.24	3.32
	Energy consumption at off-peak times	cents/kWh	1.02	1.36	1.40	1.43	1.47
103	**LV TOU Capacity Network**						
	Network access charge per connection point	cents/day	50.00	53.76	55.10	56.48	57.89
	Maximum demand charge	c/kVA/day	19.61	22.53	23.09	23.67	24.26
	Capacity charge	c/kVA/day	19.61	22.53	23.09	23.67	24.26
	Energy consumption at business times	cents/kWh	3.80	4.70	4.82	4.94	5.06
	Energy consumption at evening times	cents/kWh	2.73	3.08	3.16	3.24	3.32
	Energy consumption at off-peak times	cents/kWh	1.22	1.36	1.40	1.43	1.47
High voltage time of use demand network with ActewAGL low voltage network							
111	**HV TOU Demand Network**						
	Network access charge per connection point	$/day	$19.00	$20.00	$20.50	$21.01	$21.54
	Maximum demand charge	c/kVA/day	11.86	13.33	13.67	14.01	14.36
	Capacity charge	c/kVA/day	11.86	13.33	13.67	14.01	14.36
	Energy consumption at business times	cents/kWh	2.05	2.27	2.32	2.38	2.44
	Energy consumption at	cents/kWh	1.22	1.34	1.38	1.41	1.45

Code	Description	Unit	2014/15	2015/16	2016/17	2017/18	2018/19
	evening times						
	Energy consumption at off-peak times	cents/kWh	0.49	0.51	0.52	0.53	0.55
112	**HV TOU Demand Network—Customer HV**						
	Network access charge per connection point	$/day	$19.00	$20.00	$20.50	$21.01	$21.54
	Maximum demand charge	c/kVA/day	10.96	12.33	12.64	12.96	13.28
	Capacity charge	c/kVA/day	10.96	12.33	12.64	12.96	13.28
	Energy consumption at business times	cents/kWh	2.05	2.27	2.32	2.38	2.44
	Energy consumption at evening times	cents/kWh	1.22	1.34	1.38	1.41	1.45
	Energy consumption at off-peak times	cents/kWh	0.49	0.51	0.52	0.53	0.55
High voltage time of use demand network without ActewAGL low voltage network							
121	**HV TOU Demand Network—Customer LV**						
	Network access charge per connection point	$/day	$19.00	$20.00	$20.50	$21.01	$21.54
	Maximum demand charge	c/kVA/day	11.98	17.40	17.84	18.28	18.74
	Capacity charge	c/kVA/day	11.98	17.40	17.84	18.28	18.74
	Energy consumption at business times	cents/kWh	1.67	2.99	3.06	3.14	3.22
	Energy consumption at evening times	cents/kWh	0.88	1.54	1.58	1.62	1.66
	Energy consumption at off-peak times	cents/kWh	0.36	0.60	0.62	0.63	0.65
122	**HV TOU Demand Network—Customer HV and LV**						
	Network access charge per connection point	$/day	19.00	20.00	20.50	21.01	21.54
	Maximum demand charge	c/kVA/day	14.64	16.40	16.81	17.23	17.66
	Capacity charge	c/kVA/day	14.64	16.40	16.81	17.23	17.66
	Energy consumption at business times	cents/kWh	2.39	2.99	3.06	3.14	3.22
	Energy consumption at evening times	cents/kWh	1.44	1.54	1.58	1.62	1.66

Code	Description	Unit	2014/15	2015/16	2016/17	2017/18	2018/19
	Energy consumption at off-peak times	cents/kWh	0.70	0.60	0.62	0.63	0.65
135	**Small Unmetered Loads Network**						
	Network access charge	cents/day	37.70	40.30	41.31	42.34	43.40
	Energy consumption	cents/kWh	9.13	10.20	10.46	10.72	10.99

10.6.1 Impacts of jurisdictional schemes

In the 2009–14 regulatory period, costs associated with ACT jurisdictional schemes, including feed-in tariffs, the UNFT and the EIL, have been included in DUoS prices. However, in the transitional and subsequent regulatory periods, these costs are to be excluded from DUoS and recovered in a separate jurisdictional scheme charge included in network use of system (NUoS) charges.

In 2015/16, the second year under the new jurisdictional scheme arrangements, the cost of jurisdictional schemes are estimated to amount to $29.04 million (after the refund of over recoveries in previous years) and will contribute an average of 1.04 cents per kWh to network charges.

10.6.2 Impacts of dual function assets on DUOS prices

A further factor influencing the comparison of DUoS prices between the 2009–14 regulatory period and the transitional and subsequent periods is the pricing of services provided by dual function assets.

In March 2012, the ACT network was connected to the TransGrid's transmission network at Williamsdale. Since then, ActewAGL Distribution's 132 kV network has been supporting TransGrid's transmission network. This change in function meant that most of ActewAGL Distribution's 132 kV network became classified as dual function assets.

The AER has approved ActewAGL Distribution's recovery of the costs of these assets in transmission charges.[907] Part of the cost of these dual function assets will be recovered in New South Wales with the remainder recovered from ACT customers through transmission charges. The removal of the cost of the dual function assets from the cost of the distribution network has

[907] AER 2013, *Stage 1 Framework and approach paper ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, March

contributed to the reduction in indicative DUOS charges, from the 2009–14 regulatory period to the transitional and subsequent regulatory periods.

10.7 Estimated impacts of DUoS and metering charges on average bills

DUoS and metering charges are estimated to represent about one third of retail tariffs for consumers on regulated retail tariffs in 2015/16 (excluding carbon tax and GST). Therefore, a change in DUoS and metering charges of 3 per cent will change retail prices by just 1 per cent. With all the network charges included (that is, DUoS plus transmission charges plus jurisdictional scheme amounts and metering), regulated retail tariffs in 2015/16 are forecast to rise on average by 3.7 per cent in real terms (6.3 per cent in nominal terms), other things being equal.

The following tables show the estimated impact of the proposed standard control and alternative control charges on average consumers' bills.[908] The estimated bills for 2013/14 and 2014/15 are based on the actual regulated retail prices for that year. The estimated bills for 2015/16 are based upon the forecast prices. For subsequent years, the retail component together with TUoS charges and the cost of jurisdictional schemes are assumed to be constant. This allows the impact on consumer bills of the proposed changes to DUoS and metering charges to be assessed. In determining these charges, the CPI applied in 2015/16 and subsequent years was 2.50 per cent. GST is assumed to be 10 per cent over the regulatory period.

For a residential customer consuming 5,000 kWh per annum on the regulated Home Plan tariff, the impact of the proposed standard control and alternative control (metering) charges on the annual bill is shown in Table 10.2.

[908] The proposed prices for alternative control metering services are provided in Chapter 14 of this revised regulatory proposal.

Table 10.2 Residential basic bill—5 MWh (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$449	$390	$404	$412	$420	$428
Retail, TUOS & JS	$826	$801	$868	$868	$868	$868
Total Bill	$1,275	$1,192	$1,273	$1,280	$1,288	$1,297
% Change		**-6.5%**	**6.8%**	**0.6%**	**0.6%**	**0.6%**

For a residential customer consuming 4,000 kWh per annum on the Home Plan tariff and 2,500 kWh per annum on the off-peak (night and day) tariff, the impact of the ActewAGL Distribution's proposal is shown in Table 10.3.

Table 10.3 Residential basic with off-peak bill—4 MWh basic and 2.5 MWh off-peak (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$392	$348	$367	$374	$381	$389
Retail, TUOS & JS	$969	$915	$944	$944	$944	$944
Total Bill	$1,361	$1,263	$1,312	$1,319	$1,326	$1,333
% Change		**-7.2%**	**3.8%**	**0.5%**	**0.5%**	**0.6%**

For a residential consumer on the residential time-of-use tariff, and consuming 6,000 kWh per annum of which 1,750 kWh per annum is at max times, 2,540 kWh per annum is at mid times, and 1,710 kWh is at economy times, the impact of the proposal is as shown in Table 10.4.

Table 10.4 Residential TOU bill 6 MWh: 1.75/2.54/1.71 MWh (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$560	$508	$591	$604	$616	$629
Retail, TUOS & JS	$875	$807	$809	$809	$809	$809
Total Bill	$1,434	$1,315	$1,400	$1,412	$1,425	$1,438
% Change		**-8.3%**	**6.5%**	**0.9%**	**0.9%**	**0.9%**

For a residential customer on the Home Saver Plan, consuming 9,000 kWh per annum, the impact to this proposal is as shown in Table 10.5.

Table 10.5 Residential Home Saver Tariff bill—9 MWh (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$630	$526	$635	$648	$662	$677
Retail, TUOS & JS	$1,383	$1,333	$1,333	$1,333	$1,333	$1,333
Total Bill	$2,013	$1,859	$1,967	$1,981	$1,995	$2,009
% Change		**-7.6%**	**5.8%**	**0.7%**	**0.7%**	**0.7%**

For a customer on the residential Home Saver Plus Plan and consuming 14,000 kWh per annum, the impact of this proposal is as shown in Table 10.6.

Table 10.6 Residential Home Saver Plus Tariff bill—14 MWh (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$840	$654	$790	$807	$825	$844
Retail, TUOS & JS	$2,041	$1,984	$2,002	$2,002	$2,002	$2,002
Total Bill	$2,881	$2,638	$2,792	$2,809	$2,827	$2,846
% Change		**-8.4%**	**5.8%**	**0.6%**	**0.6%**	**0.7%**

For a small commercial customer on the General Tariff and consuming 20 MWh per annum, the impact of the proposal is as shown in Table 10.7.

Table 10.7 Commercial—General Tariff bill—20 MWh (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$2,262	$2,099	$2,160	$2,211	$2,263	$2,316
Retail, TUOS & JS	$3,217	$2,999	$3,323	$3,323	$3,323	$3,323
Total Bill	$5,479	$5,098	$5,483	$5,534	$5,586	$5,639
% Change		**-7.0%**	**7.6%**	**0.9%**	**0.9%**	**1.0%**

For an average commercial customer on the General Time-of-Use tariff using 40 MWh per annum, the impact of the proposal is as shown in Table 10.8.

Table 10.8 Commercial—General TOU Tariff bill—40 MWh (15/8/17 MWh) (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$4,489	$3,938	$4,534	$4,644	$4,757	$4,872
Retail, TUOS & JS	$5,359	$5,062	$5,204	$5,204	$5,204	$5,204
Total Bill	$9,849	$9,000	$9,738	$9,848	$9,961	$10,077
% Change		**-8.6%**	**8.2%**	**1.1%**	**1.1%**	**1.2%**

Large commercial customers on the low voltage demand tariff face demand as well as time-of use charges. For a customer with an average profile consuming 500 MWh per annum, the proposed prices have the impact shown in Table 10.9.

Table 10.9 Low Voltage Demand Tariff bill—500 MWh (208/72/220 MWh, 130 kVA) (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$36,873	$29,259	$38,319	$39,258	$40,219	$41,205
Retail, TUOS & JS	$71,069	$69,279	$67,775	$67,775	$67,775	$67,775
Total Bill	$107,942	$98,538	$106,094	$107,033	$107,994	$108,980
% Change		**-8.7%**	**7.7%**	**0.9%**	**0.9%**	**0.9%**

For larger commercial customers using the low voltage capacity charge using 1 GWh per annum, the estimated impact of the proposal is shown in Table 10.10.

Table 10.10 Low Voltage Capacity Tariff bill—1 GWh (350/150/500 MWh; 190/225 kVA) (including GST)

$ nominal	*2013/14*	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
DUOS & metering	$60,185	$59,441	$69,214	$70,924	$72,678	$74,475
Retail, TUOS & JS	$136,693	$119,190	$121,729	$121,729	$121,729	$121,729
Total Bill	$196,879	$178,630	$190,943	$192,653	$194,407	$196,204
% Change		**-9.3%**	**6.9%**	**0.9%**	**0.9%**	**0.9%**

11 Pass through events

11.1 Introduction

This Chapter 11 responds to the AER's draft decision on the additional pass through events that are to apply for the subsequent regulatory period in accordance with clause 6.5.10 of the Rules (nominated pass through events) set out in Attachment 15 to its draft decision.

In its regulatory proposal for the subsequent regulatory period, ActewAGL Distribution proposed, as nominated pass through events, a general pass through event, an insurer credit risk event, a Demand Management and Embedded Generation Connection Incentive Scheme event (DMEGCIS event) and an insurance cap event.

In its draft decision, the AER does not accept that ActewAGL Distribution's proposed general pass through event, insurer credit risk event or DMEGCIS event should apply for the subsequent regulatory period.[909] With respect to the insurance cap event, the AER accepts that an event of the relevant kind should apply in the subsequent regulatory period but does not accept ActewAGL Distribution's proposed definition of that event. Accordingly, the AER proposes an alternate definition for the insurance cap event.

After considering the AER’s draft decision on nominated pass through events, ActewAGL Distribution accepts the AER's draft decision that a DMEGCIS event should not apply in the subsequent regulatory period. However, ActewAGL Distribution rejects the AER's draft decision not to accept ActewAGL Distribution's proposed general pass through event and insurer credit risk event. In addition, it does not wholly accept the AER's draft decision on the definition of the insurance cap event.

As a result, ActewAGL Distribution's revised proposal continues to propose the following events as nominated pass through events:

- an insurance cap event;
- an insurer credit risk event; and
- a general pass through event.

ActewAGL Distribution's revised proposal proposes revisions to the AER's definition of the insurance cap event. ActewAGL Distribution also proposes revisions to its definitions of the

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[909] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 15*, p. 15-7

proposed general pass through event and insurer credit risk event to address the concerns raised by the AER with those events in its draft decision.

As a consequence of the revisions to its proposed definition of the general pass through event necessary to address the AER's draft decision in respect of that proposed event (which revisions limit the scope of that proposed event), ActewAGL Distribution further proposes in this revised proposal that a terrorism event and a natural disaster event of the kind accepted by the AER in its draft decision on Ausgrid's forthcoming distribution determination for the 2015-16 to 2018-19 regulatory control period (Ausgrid draft decision)[910] apply to ActewAGL Distribution in the SRP in addition to the general pass through event. ActewAGL Distribution's proposed definitions of the terrorism event and the natural disaster event are substantively similar to those decided by the AER in the Ausgrid draft decision.

ActewAGL Distribution also proposes, in the event that the AER does not accept augex for the Molonglo zone substation in its final decision, a Molonglo pass through event be specified in the distribution determination as an additional pass thorugh event to apply for the subsequent regulatory period in accordance with clause 6.5.10 of the Rules. This is further discussed in Chapter 4.

ActewAGL Distribution's response to the AER's draft decision and its revised proposal in respect of its proposed insurance cap event, insurer credit risk event and general pass through event are discussed in greater detail in sections 11.4.2, 11.4.3 and 11.4.4 respectively below. ActewAGL Distribution's proposal, in this revised proposal, of a terrorism event and a natural disaster event (as a consequence of addressing the AER's draft decision on the general pass through event) is also discussed in section 11.5.4 below.

11.2 The relevant legal and regulatory framework for nominated pass through events

11.2.1 The NEO and the RPPs

The AER must perform or exercise a function or power under the NEL or the Rules that relates to the making of a distribution determination in a manner that will or is likely to contribute to the achievement of the NEO (NEL, section 16(1)(a) and section 2(1) definition of 'AER economic regulatory function or power'). Further, in making a distribution determination, if there are 2 or more decisions that will or are likely to contribute to the achievement of the NEO, the AER must make the decision that it is satisfied will or is likely to contribute to the achievement of the NEO

[910] AER 2014, Draft decision Ausgrid distribution determination 2015-16 to 2018-19, Attachment 15: Cost pass through, pp. 15-14 to 15-15

to the greatest degree (NEL, section 16(1)(d) and sections 2(1) and 71A definitions of 'reviewable regulatory decision').

The NEO is set out in section 7 of the NEL and reads as follows:

> *The objective of this Law 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-*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system.*

Economic efficiency, including efficient investment in the system with which the provider provides services, is thus the ultimate objective of the regulatory regime established by the NEL and Rules. The interests of consumers of electricity with which the NEO is concerned are those in obtaining lower prices (than would otherwise be the case), increased quality, safety, reliability and security of supply and the increased reliability, safety and security of the national electricity system.[911]

The phrase 'long term' is concerned with the period over which the full effects of the AER's decision will be felt.[912] In the 'long term', the interests of consumers are enhanced by sustainably low prices, rather than very low prices, that support competitive, but sustainable, service provision.[913]

The NEO is, thus, concerned with the long term interests of consumers in sustainably low prices, and the maintenance or enhancement of quality, safety, reliability and security, rather than the pursuit of price reductions in the short-term at the expense of their other interests.[914]

In addition, the AER must take into account the RPPs when exercising a discretion in making those parts of a distribution determination relating to direct control network services (NEL, section 16(2)(a)). The RPPs in section 7A can be taken to be consistent with and to promote the

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[911] *Re Seven Network Limited (No 4)* (2004) ACompT 11 at [120], in discussing the objective of Part XIC of the *Trade Practices Act 1974* (Cth) (**TPA**) (now the *Competition and Consumer Act 2010* (Cth) (**CCA**)), being the long term interests of end-users', on which the NEO was modelled.

[912] *Re Seven Network Limited (No 4)* (2004) ACompT 11 at [120]; *Application by Chime Communications Pty Ltd (No 2)* [2009] ACompT 2 at [15], in discussing the objective of Part XIC of the TPA (now the CCA), being the long term interests of end-users', on which the NEO was modelled.

[913] *Re Seven Network Limited (No 4)* (2004) ACompT 11 at [121]

[914] *Re Application by ElectraNet Pty Limited (No 3)* [2008] ACompT 3 at [251].

objectives in section 7. The principles are themselves stated normatively in the form of what is intended to be achieved.[915]

The RPPs are set out in section 7A of the NEL and relevantly include:

> *(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in-*
>
> *(a) providing direct control network services; and*
>
> *(b) complying with a regulatory obligation or requirement or making a regulatory payment.*
>
> *(3) 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-*
>
> *(a) efficient investment in a distribution system … with which the operator provides direct control network services; and*
>
> *(b) the efficient provision of electricity network services; and*
>
> *(c) the efficient use of the distribution system … with which the operator provides direct control network services.*
>
> *…*
>
> *(5) 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.*

11.2.2 Constituent decision on nominated pass through events

Clause 6.12.1(14) of the Rules provides that one of the constituent decisions by the AER on which the distribution determination for ActewAGL Distribution for the subsequent regulatory period is predicated is a decision on the additional pass through events that are to apply for the regulatory control period in accordance with clause 6.5.10.

Clause 6.5.10 of the Rules provides that:

- a building block proposal may include a proposal as to the events that should be defined as pass through events under clause 6.6.1(a1)(5) having regard to the 'nominated pass through event considerations'; and

[915] *Application by Energy Australia and Others* [2009] ACompT 8 (with Corrigendum) at [79]

- in determining whether to accept the pass through events nominated by ActewAGL Distribution in its building block proposal, the AER must take into account those considerations.

The definition of 'nominated pass through event considerations' in Chapter 10 of the Rules provides:

> *The* nominated pass through event considerations *are:*
>
> *(a)* *whether the event proposed is an event covered by a category of* pass through event *specified in clause 6.6.1(a1)(1) to (4) (in the case of a distribution determination) … ;*
>
> *(b)* *whether the nature or type of event can be clearly identified at the time the determination is made for the service provider;*
>
> *(c)* *whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;*
>
> *(d)* *whether the relevant service provider could insure against the event, having regard to:*
>
> *(1)* *the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or*
>
> *(2)* *whether the event can be self-insured on the basis that:*
>
> *(i)* *it is possible to calculate the self-insurance premium; and*
>
> *(ii)* *the potential cost to the relevant service provider would not have a significant impact on the service provider's ability to provide* network services*; and. [sic]*
>
> *(e)* *any other matter the* AER *considers relevant and which the* AER *has notified* Network Service Providers *is a nominated pass through event consideration.*

Clause 11.56.4(b) to (f) of the Rules provides for the application of specified provisions of current Chapter 6 of the Rules on the basis that the transitional regulatory period is to be treated as either the last regulatory year of the 2009-14 regulatory control period or the first regulatory year of the subsequent regulatory period. Clause 11.56.4(g), in turn, provides that nothing in clause 11.56.4 has the effect of actually rendering the transitional regulatory period as the first regulatory year of the subsequent regulatory period and, except for the purposes of the application of paragraphs (b) to (f) in accordance with their terms, the transitional regulatory period must be treated as a regulatory control period that is separate to the subsequent regulatory period.

The provisions of current Chapter 6 set out above are not referred to in paragraphs (b) to (f) of clause 11.56.4. It follows that the AER's decision on nominated pass through events for ActewAGL Distribution's distribution determination for the subsequent regulatory period applies only in the subsequent regulatory period.[916]

11.3 ActewAGL Distribution's proposal

In its regulatory proposal for the subsequent regulatory period, ActewAGL Distribution proposed the following events be defined as additional pass through events for the purposes of clause 6.6.1(a1)(5) of the Rules:[917]

- a general pass through event;
- a insurer credit risk event;
- an insurance cap event; and
- a DMEGCIS event.

ActewAGL Distribution's proposed definitions for each of these proposed nominated pass through events are set out in Table 11.1 below.[918]

[916] Clause 11.56.3(a)(8) of the Rules required the distribution determination made by the AER for ActewAGL Distribution for the TRP to specify, as the additional pass through events to apply for the TRP, the same additional pass through events that were decided in the distribution determination for ActewAGL Distribution for the 2009-14 regulatory control period, as well as the 'terrorism event' as defined in the Rules immediately prior to the date on which the *National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012* came into force.

[917] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 379

[918] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 381-382, 386, 387 and 390

Table 11.1 ActewAGL Distribution's proposed nominated pass through events[919]

Proposed event	Proposed definition
General pass through event	A general nominated pass through event occurs when: (1) ActewAGL Distribution could not reasonably prevent the event from occurring or substantially mitigate the cost impact of the event; and (2) the event does not fall into any definition listed in clause 6.6.1(a1)(1) to (4) of the NER.
Insurer credit risk event	An insurer credit risk event occurs if as a result of the insolvency of an insurer, ActewAGL Distribution: (a) incurs higher or lower costs for insurance premiums than those allowed for in the distribution determination; (b) in respect of a claim for a risk that would have been insured by ActewAGL Distribution's insurers, is subject to a higher or lower claim limit or higher or lower deductible than would have applied under that policy; and/or (c) incurs additional costs associated with self funding an insurance claim, which would have otherwise been covered by the insolvent insurer.
Insurance cap event	An insurance cap event occurs if: (a) ActewAGL Distribution makes a claim on an insurance policy that it holds; (b) ActewAGL Distribution incurs costs beyond the policy limit for the relevant insurance policy; and (c) ActewAGL Distribution must bear the costs that are in excess of the policy limit.
DMEGCIS event	A DMEGCIS event occurs if: (a) ActewAGL Distribution incurs or is likely to incur an increase or decrease in costs as a result of participation in a replacement of the demand management and embedded generation connection incentive scheme at the time of the subsequent regulatory proposal; and (b) the event does not fall into any definition listed in clause 6.6.1(a1)(1) to (4) of the NER.

[919] In reproducing in this Table the definitions of its proposed nominated pass through events proposed by ActewAGL Distribution in its regulatory proposal for the SRP, ActewAGL Distribution has corrected any manifest errors appearing therein.

In proposing these nominated pass through events, ActewAGL Distribution had regard to the nominated pass through event considerations specified in the Rules.[920]

11.4 AER draft decision

11.4.1 Overview

In its draft decision, the AER does not accept ActewAGL Distribution's proposed general pass through event, insurer credit risk event or DMEGCIS event should apply for the subsequent regulatory period.[921] With respect to the insurance cap event, the AER accepts that an event of the relevant kind should apply in the subsequent regulatory period but does not accept ActewAGL Distribution's proposed definition of that event. Accordingly, the AER proposes an alternate definition for the insurance cap event.

The AER purports to rely on paragraph (e) of the definition of 'nominated pass through event considerations' in Chapter 10 of the Rules to have regard, in making its constituent decision on nominated pass through events, for consistency in its approach to assessing nominated pass through events across its determination where possible.[922]

The AER's draft decisions in respect of each of the nominated pass through events proposed by ActewAGL Distribution in its regulatory proposal for the subsequent regulatory period are discussed below.

11.4.2 Insurance cap event

The AER accepts that an insurance cap event is necessary to protect ActewAGL Distribution from high cost impact events which it would be uneconomical to insure against, having regard to the limited extent to which ActewAGL Distribution is able to reasonably prevent costs being incurred which exceed its insurance cap or take steps to mitigate incurring costs.[923] The AER further

[920] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 379-380, 383-385, 387, 389 and 391-392

[921] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 15*, p. 15-7

[922] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 15*, p. 15-10

[923] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 15*, pp. 15-10 to 15-11

observes that such an event facilitates the capping of insurance coverage at a level beyond which it is uneconomic to insure, having regard to the cost of premiums and the likelihood of the event, to the benefit of consumers.

However, the AER determines on the following alternate definition for the insurance cap event:[924]

> *An insurance cap event occurs if:*
>
> *1. ActewAGL makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy,*
>
> *2. ActewAGL incurs costs beyond the relevant policy limit, and*
>
> *3. the costs beyond the relevant policy limit materially increase the costs to ActewAGL in providing direct control services.*
>
> *For this insurance cap event:*
>
> *4. the relevant policy limit is the greater of:*
>
> *a. ActewAGL's actual policy limit at the time of the event that gives, or would have given rise to a claim, and*
>
> *b. the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the regulatory control period in which the insurance policy is issued.*
>
> *5. A relevant insurance policy is an insurance policy held during the 2015-19 regulatory control period or a previous regulatory control period in which ActewAGL was regulated.*
>
> *Note for the avoidance of doubt, in assessing an insurance cap event cost pass through application under rule 6.6.1(j), the AER will have regard to:*
>
> *i. the insurance policy for the event, and*
>
> *ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event*
>
> *iii. the extent to which a prudent provider could reasonably mitigate the impact of the event.*

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[924] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 15*, p. 15-14

The AER's explanation of the revisions made to the definition of the insurance cap event proposed by ActewAGL Distribution is limited to observing that the amendments clarify some factors to which the AER will have regard when assessing a claim and assist to ensure the application of the insurance cap event in the subsequent regulatory period provides an incentive for ActewAGL Distribution to obtain an efficient level of insurance.[925]

11.4.3 Insurer credit risk event

The AER does not accept that ActewAGL Distribution's proposed insurer credit risk event should apply in the subsequent regulatory period because it considers that a prudent service provider could reasonably prevent an event of that nature from occurring.[926] The AER reasons that:

- NSPs can assess the financial viability of an insurance provider and a prudent provider would use an insurance provider that has the capacity to satisfy any claims under a policy;
- the application of a nominated pass through event of the kind proposed may dampen ActewAGL Distribution's incentives to review the viability of insurance providers and obtain insurance only from viable providers; and
- in any event, it is unclear why ActewAGL Distribution would incur a higher or lower deductible or materially different insurance premium as a consequence of an insurer becoming insolvent.

11.4.4 General pass through event

The AER does not accept that ActewAGL Distribution's proposed general pass through event should apply in the subsequent regulatory period because:[927]

- the nature or type of the event cannot be clearly identified at the time the distribution determination for ActewAGL Distribution for the subsequent regulatory period is made;
- the AER therefore cannot consider whether ActewAGL Distribution can insure against the event; and

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925 AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 15*, p. 15-11

926 AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 15*, pp. 15-11 to 15-12

927 AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 15*, pp. 15-12 to 15-13

- the application of the proposed general pass through event in the subsequent regulatory period would not contribute to the achievement of the NEO or be consistent with the RPPs.

11.4.5 DMEGCIS event

The AER does not accept that ActewAGL Distribution's proposed DMEGCIS event should apply in the subsequent regulatory period because:[928]

- the event is likely covered by a pass through event specified in clause 6.6.1(a1)(1) to (4) of the Rules;
- the AER expects that any AEMC Rule change that provides for the introduction of a new or revised demand management related incentive scheme would specify the DNSPs to whom it is to apply and, if it is to apply to ActewAGL Distribution in the subsequent regulatory period, would provide for ActewAGL Distribution to receive any incentives thereunder for example through the establishment of transitional rules; and
- in any event, the application of an event of the kind proposed by ActewAGL Distribution would not operate so as to provide for ActewAGL Distribution to receive any such incentives as the pass through regime established by clause 6.6.1 of the Rules provides only for the pass through of the cost impact of a pass through event.

11.5 ActewAGL Distribution's response and revised proposal

11.5.1 Overview

After considering the AER's draft decision on nominated pass through events, ActewAGL Distribution accepts the AER's draft decision that a DMEGCIS event should not apply in the subsequent regulatory period. This is because ActewAGL Distribution accepts that its relevant concerns could be addressed by transitional rules established by any AEMC Rule change that provides for the introduction of a new or revised demand management related incentive scheme.

However, ActewAGL Distribution rejects the AER's draft decision that ActewAGL Distribution's proposed general pass through event and insurer credit risk event should not apply in the subsequent regulatory period. In addition, it does not wholly accept the AER's draft decision on the definition of the insurance cap event.

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[928] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 15*, p. 15-13

As a result, ActewAGL Distribution's revised proposal continues to propose the following events as nominated pass through events:

- an insurance cap event;
- an insurer credit risk event; and
- a general pass through event.

ActewAGL Distribution's revised proposal proposes revisions to the AER's definition of the insurance cap event. ActewAGL Distribution also proposes revisions to its definitions of the proposed general pass through event and insurer credit risk event to address the concerns raised by the AER with those events in its draft decision.

Finally, as a consequence of the revisions to its proposed definition of the general pass through event necessary to address the AER's draft decision in respect of that proposed event (which revisions limit the scope of that proposed event), ActewAGL Distribution further proposes in this revised proposal that a terrorism event and a natural disaster event of the kind accepted by the AER in the Ausgrid draft decision[929] apply to ActewAGL Distribution in the subsequent regulatory period in addition to its revised proposed general pass through event. ActewAGL Distribution's proposed definitions of the terrorism event and the natural disaster event are substantively similar to those decided by the AER in the Ausgrid draft decision.

ActewAGL Distribution's response to the AER's draft decision and its revised proposal in respect of its proposed insurance cap event, insurer credit risk event and general pass through event are discussed in greater detail in sections 11.5.2, 11.5.3 and 11.5.4 respectively below. ActewAGL Distribution's proposal, in this revised proposal, of a terrorism event and a natural disaster event (as a consequence of addressing the AER's draft decision on the general pass through event) is also discussed in section 11.5.4 below.

11.5.2 Insurance cap event

ActewAGL Distribution has considered the alternate definition of the insurance cap event proposed by the AER in its draft decision and makes the following submissions in respect of that alternate definition.

First, ActewAGL Distribution objects to the conditioning of the occurrence of an insurance cap event by the AER's alternate definition on the receipt of a benefit under the relevant insurance policy.

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[929] AER 2014, Draft decision Ausgrid distribution determination 2015-16 to 2018-19, Attachment 15: Cost pass through, pp. 15-14 to 15-15

In contrast to ActewAGL Distribution's proposed definition, the AER's alternate definition conditions the occurrence of an insurance cap event on ActewAGL Distribution 'receiv[ing] the benefit of a payment or payments under a relevant insurance policy'. While the AER does not provide any explanation of this aspect of its alternate definition, ActewAGL Distribution presumes that the AER's intent is to limit the occurrence of an insurance cap event to circumstances in which ActewAGL Distribution's claim is in accordance with the terms of the relevant policy.

ActewAGL Distribution objects to the conditioning of the occurrence of an insurance cap event on the receipt of a benefit under the relevant policy because this will prevent it from recovering costs beyond the policy limit where a benefit is not received regardless of the circumstances in which this occurs. ActewAGL Distribution may not receive a benefit notwithstanding that a claim is made in accordance with the insurance policy for various reasons, including for example the insolvency of an insurer or the insurer raising an unmeritorious dispute to the claim or otherwise seeking to evade or failing to honour its contractual obligations.

It follows that the conditioning of the occurrence of an insurance cap event in the manner proposed by the AER would operate to deny ActewAGL Distribution with the very protection from high cost impact events it would be uneconomical to insure against that the AER recognises, in its draft decision, is necessary and to the benefit of consumers in circumstances where ActewAGL Distribution does not receive any benefit under the policy for reasons wholly unrelated to the merits of its claim and notwithstanding that ActewAGL Distribution could not have acted to prevent this. Such an outcome would likely operate to deny ActewAGL Distribution the opportunity to recover its efficient costs and is not consistent with the nominated pass through event considerations, the NEO or the RPPs.

ActewAGL Distribution therefore proposes the AER’s alternate definition be amended to condition the occurrence of an insurance cap event on the satisfaction by the claim(s) of the conditions of insurance in the relevant policy, instead of the receipt by ActewAGL Distribution of a benefit under the policy.

Secondly, ActewAGL Distribution objects to the inclusion in the AER's alternate definition of a materiality requirement.

In contrast to ActewAGL Distribution's proposed definition, the AER's alternate definition conditions the occurrence of an insurance cap event on the costs incurred by ActewAGL Distribution beyond the relevant policy limit materially increasing the costs to ActewAGL Distribution of providing direct control services. Again, the AER does not provide any explanation of this aspect of its alternate definition.

In any event, this amendment is not required because, as ActewAGL Distribution observed in its regulatory proposal for the subsequent regulatory period,[930] a DNSP may only seek to pass through the costs of a pass through event, including a nominated pass through event, under clause 6.6.1 of the Rules where the event results in a DNSP incurring materially higher costs in providing direct control services than it would have incurred but for that event. This is because, under clause 6.6.1, a DNSP may only seek to recover the costs of a 'positive change event', which is defined in Chapter 10 of the Rules to mean a pass through event that results in a DNSP incurring materially higher costs in providing direct control services than it would have incurred but for that event.

Indeed, the AER's materiality requirement is arguably inconsistent with the pass through regime established by the Rules. The term 'materially' is defined in Chapter 10 of the Rules for the purposes of the term 'positive change event' by reference to 1% of the DNSP's ARR for any regulatory year in which the DNSP incurs or is likely to incur costs as a result of the relevant event. By contrast, the term 'materially' where it appears in the AER's alternate definition of the insurance cap event would appear to take its ordinary and natural meaning.

Thirdly, ActewAGL Distribution objects to the defining of the relevant policy limit, in the AER's alternate definition, by reference to that commensurate with the allowance for insurance premiums in ActewAGL Distribution's forecast opex allowance.

In contrast to ActewAGL Distribution's proposed definition, the AER's alternate definition defines the policy limit for the purposes of that definition to be the greater of the actual policy limit and the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums in the forecast opex allowance. Once again, the AER did not provide any explanation for this aspect of its alternate definition. However, it would appear to be directed to precluding ActewAGL Distribution from both recovering the costs of an insurance premium that reflects a particular policy limit in its forecast opex allowance and the costs it incurs above an actual policy limit that is lower than that reflected in its forecast opex allowance.

ActewAGL Distribution has significant concerns with this aspect of the AER's alternate definition. While the AER's apparent policy concern is unobjectionable, the resultant limb of its alternate definition of the insurance cap event:

- lacks certainty of meaning in that the policy limit commensurate with the allowance for insurance premiums in ActewAGL Distribution's forecast opex allowance is incapable of being ascertained; and

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[930] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 382

- is, in any event, unnecessary to address the AER's apparent policy concern.

As a consequence of the regulatory approach adopted by the AER in the draft decision for determining ActewAGL Distribution's forecast opex allowance for the 2014-19 period, the AER has not determined on any allowance for insurance premiums in determining that opex allowance. In any event, even if the AER did determine a specific insurance opex allowance, it is unclear how the policy limit that is 'explicitly or implicitly commensurate' with the allowance would be ascertained. A decision by the AER to adopt a definition for a nominated pass through event, to which the Rules give legal force and effect, that lacks certainty of meaning and effect to this degree would constitute an incorrect exercise of discretion, and an unreasonable decision, in all the circumstances, as well as a decision that is not authorised by the Rules and involves an improper exercise of power.

Further, the definition of the 'relevant policy limit' by reference to that commensurate with the allowance for insurance premiums in ActewAGL Distribution's forecast opex allowance is unnecessary to address the AER's policy concern. This is because clause 6.6.1(j) of the Rules requires the AER, in making a positive change event determination, to take into account matters including the following:

> *(3) … the efficiency of the Distribution Network Service Provider's decisions and actions in relation to the risk of the positive change event, including whether the Distribution Network Service Provider has failed to take any action that could reasonably be taken to reduce the magnitude of the eligible pass through amount in respect of that positive change event and whether the Distribution Network Service Provider has taken or omitted to take any action where such action or omission has increased the magnitude of the amount in respect of that positive change event;*
>
> *…*
>
> *(7) whether the costs of the pass through event have already been factored into the calculation of the Distribution Network Service Provider's annual revenue requirement for the regulatory control period in which the pass through event occurred or will be factored into the calculation of the Distribution Network Service Provider's annual revenue requirement for a subsequent regulatory control period.*

In taking into account the efficiency of ActewAGL Distribution’s actions and whether ActewAGL Distribution failed to take any action that could reasonably be taken to reduce the magnitude of the event, the AER could consider the policy limit of the relevant insurance policy. In taking into account whether the costs of the insurance cap event have already been factored into the calculation of ActewAGL Distribution's ARR for the subsequent regulatory period, the AER could consider whether and the extent to which the costs of an insurance premium that reflects a policy limit higher than that reflected in the relevant insurance policy was reflected in ActewAGL Distribution's forecast opex allowance for the subsequent regulatory period.

For this reason also, a decision by the AER to adopt a definition for the insurance cap event that defines the 'relevant policy limit' for the purposes of that definition by reference to 'the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance' would constitute an incorrect exercise of discretion, and an unreasonable decision, in all the circumstances, as well as a decision that is not authorised by the Rules and involves an improper exercise of power.

Accordingly, ActewAGL Distribution proposes the deletion of the definition of 'relevant policy limit' in the AER's alternate definition and the incorporation of the first limb of that 'relevant policy limit' definition directly into paragraph 2 of the definition of the insurance cap event.

ActewAGL Distribution therefore proposes the following revised definition of the insurance cap event (with the revisions proposed by ActewAGL Distribution to the AER's alternate definition shown in hard mark ups and green shading):

An insurance cap event occurs if:

1. ActewAGL makes a claim or claims ~~and receives the benefit of a payment or payments~~ under a relevant insurance policy that satisfies the conditions of insurance under that policy,

2. ActewAGL incurs costs beyond the actual ~~relevant~~ policy limit of the relevant insurance policy at the time of the event that gives rise to the relevant claim.~~, and~~

~~3. the costs beyond the relevant policy limit materially increase the costs to ActewAGL in providing direct control services.~~

For this insurance cap event,~~:~~

~~4. the relevant policy limit is the greater of:~~

~~a. ActewAGL's actual policy limit at the time of the event that gives, or would have given rise to a claim, and~~

~~b. the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the regulatory control period in which the insurance policy is issued.~~

~~5.~~ ~~A~~a relevant insurance policy is an insurance policy held during the 2015-19 regulatory control period or a previous regulatory control period in which ActewAGL was regulated.

~~Note for the avoidance of doubt, in assessing an insurance cap event cost pass through application under rule 6.6.1(j), the AER will have regard to:~~

~~i. the insurance policy for the event, and~~

~~ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event~~

~~iii. the extent to which a prudent provider could reasonably mitigate the impact of the event.~~

11.5.3 Insurer credit risk event

ActewAGL Distribution agrees with the AER that a prudent service provider would assess an insurance provider's financial viability and use an insurance provider that is expected to have the capacity to satisfy any claims under a policy. Accordingly, ActewAGL Distribution scrutinises market developments, insurer reputation, credit rating and financial stabilities of potential insuring entities. ActewAGL Distribution relies on information provided by its insurance broker, Marsh, and heeds Marsh's minimum guidelines for insurance entities. Where possible, ActewAGL Distribution selects insurers with a credit rating of BBB or higher, although this may not be possible in the future if an event affects the credit worthiness of the insurance industry as a whole.

ActewAGL Distribution notes that general insurers are supervised by the Australian Prudential Regulation Authority (APRA). Prudential Standards include the requirement for general insurers to maintain adequate capital against the risks associated with its activities,[931] maintain assets in Australia of a value that equals or exceeds the total amount of the general insurer's liabilities in Australia[932] and maintain a risk management framework and strategy that is appropriate to the nature and scale of its operations.[933]

Nonetheless, despite acting prudently in selecting an insurance provider, the existence of prudential standards and the oversight by APRA of the insurance industry's compliance with those standards, an insurer may still fail. This risk is beyond the control of ActewAGL Distribution.

To ensure that ActewAGL Distribution has the opportunity to recover at least its efficient costs, this revised regulatory proposal includes an insurer credit risk event. To address the AER's concerns regarding incentive effects, ActewAGL Distribution proposes revisions to its proposed definition of the insurer credit risk event that operate to confine the recovery of costs incurred by ActewAGL Distribution in self-funding an insurance claim as a consequence of such an event to circumstances where ActewAGL Distribution acted prudently in selecting the relevant insurer.

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[931] Attachment G2 Prudential Standard GPS 110

[932] Attachment G3 Prudential Standard GPS 120

[933] Attachment G4 Prudential Standard GPS 220

ActewAGL Distribution's revised proposed definition for the insurer credit risk event is as follows (with the revisions now proposed by ActewAGL Distribution to the definition it proposed in its regulatory proposal for the subsequent regulatory period shown in hard mark ups and green shading):

An insurer credit risk event occurs if:

(1) as a result of the insolvency of an insurer, ActewAGL Distribution:

(a) incurs higher or lower costs for insurance premiums ~~than those allowed for in the distribution determination~~;

(b) in respect of a claim for a risk that would have been insured by ActewAGL Distribution's insurers, is subject to a higher or lower claim limit or higher or lower deductible than would have otherwise applied under the~~at~~ relevant policy; and/or

(c) incurs additional costs associated with self-funding an insurance claim, which would have otherwise been covered by the insolvent insurer; and

(2) at the time of taking any relevant insurance policy or policies with the insolvent insurer, ActewAGL Distribution took reasonable steps to assess the financial viability of the insolvent insurer and ensure that that insurer had the capacity to satisfy any claims under the relevant policy or policies.

Turning to the AER's conclusion that it is unclear why ActewAGL Distribution will incur a higher or lower deductible, or materially different insurance premium, as a consequence of an insurer becoming insolvent, ActewAGL Distribution observes that this AER conclusion is difficult to reconcile with conclusions reached by the AER in accepting insurer credit risk events in the course of making past distribution determinations. In particular, in deciding to accept an insurer credit risk event as a nominated pass through event in its draft decision for the Victorian DNSPs for the 2011-15 regulatory control period (which decision was subsequently applied in its final decision[934]), the AER's reasons for decision were as follows:[935]

> *The AER accepts that the occurrence of increased insurance premiums (or deductibles) from external insurers (where the original insurer becomes insolvent) is largely beyond the control of the DNSP (subject to any choice that the DNSP has with regards to insurance companies), and*

[934] AER 2010, *Victorian electricity distribution network service providers Distribution determination 2011-2015, Final Decision*, October 2010, pp. 783-783

[935] AER 2010, *Victorian electricity distribution network service providers Distribution determination 2011-2015, Draft Decision*, June 2010, p. 725

> *that the costs associated with higher insurance premiums are also beyond the control of the DNSP (in that they cannot be mitigated). The AER acknowledges that such costs should be allowed in the regulatory regime.*

In any event, as recognised by the AER in accepting the insurer credit risk event for the Victorian DNSPs, insurance premiums and/or deductibles may increase because of a negative shock, as a consequence of an insurer becoming insolvent and decreasing industry capital. As Cagle and Harrington note:

> *It may be very costly for insurers to issue new equity immediately following a negative shock to capital because of agency costs, such as those that arise from asymmetrical information in capital markets. The decline in capital may thus constrain the capacity to write coverage; i.e., it may cause the supply curve for existing firms to shift backward. If immediate and substantial supply by new entrants is infeasible, the resulting increase in price will provide at least partial shifting of the cost of the shock to policyholders.* [936]

Accordingly, a negative shock to insurance industry capital could cause premiums and/or deductibles to increase, at least temporarily. If any change in premium and/or deductibles does not give rise to a material change in ActewAGL Distribution's costs, for example because that change in premium and/or deductibles is only temporary, then ActewAGL Distribution will not be able to pass through the cost consequences of that change in premium and/or deductibles.[937]

11.5.4 General pass through event

Revised proposed general pass through event

ActewAGL Distribution maintains its proposal that a general pass through event should apply in the subsequent regulatory period.

To address the concerns raised by the AER in its draft decision regarding the application of such an event in the subsequent regulatory period, however, ActewAGL Distribution proposes the following revised definition for its proposed general pass through event (with the revisions now proposed by ActewAGL Distribution to the definition it proposed in its regulatory proposal for the subsequent regulatory period shown in hard mark ups and green shading):

> A general ~~nominated~~ pass through event occurs if an event occurs that ~~when~~:

[936] Attachment G5. Cagle J. and Harrington, S 1995, *Insurance supply with capacity constraints and endogenous insolvency risk,* Journal of Risk and Uncertainty, Vol. 11 Issue 3, December, pp. 219-220

[937] See definitions of 'positive change event' and 'negative change event' in Chapter 10 of the Rules

(1) was not reasonably foreseeable at the time of making the distribution determination for ActewAGL Distribution for the subsequent regulatory period;

(2) could not have been insured against on reasonable commercial terms or self insured, at the time of making the distribution determination for ActewAGL Distribution for the subsequent regulatory period;

(3) results in ActewAGL Distribution incurring higher or lower costs in providing direct control services than it would have incurred but for that event;

(4~~1~~) ~~ActewAGL Distribution~~ could not have been ~~reasonably~~ prevented, nor any increase in costs as a result thereof ~~the event from occurring or~~ substantially mitigated, by ActewAGL Distribution using reasonable endeavours ~~the cost impact of the event~~; and

(5~~2~~) is not covered by any category of pass through event specified ~~the event does not fall into any definition listed~~ in clause 6.6.1(a1)(1) to (4) of the NER or any other event specified as a pass through event in the distribution determination for ActewAGL Distribution for the subsequent regulatory period for the purposes of clause 6.6.1(a1)(5) of the NER.

Addressing first the AER's conclusion that the application of a general pass through event in the subsequent regulatory period would not contribute to the achievement of the NEO or be consistent with the RPPs, ActewAGL Distribution contends that, to the contrary, the application of its revised proposed general pass through event in the subsequent regulatory period would be consistent with the AEMC's stated policy intent in establishing the nominated pass through event considerations and accord with the AEMC's views on the circumstances in which a nominated pass through event promotes the achievement of the NEO and is consistent with the RPPs.

While the AEMC recognised that the incentive properties of cost pass throughs are very weak in establishing the nominated pass through event considerations,[938] it nonetheless concluded that the acceptance of a nominated pass through event would promote the achievement of the NEO *'when event avoidance, mitigation, commercial insurance and self-insurance are unavailable … for managing the risk of unforeseen events'*.[939] The AEMC reasoned that:[940]

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938 AEMC 2012, *Rule Determination National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012*, 2 August 2012, p. 3

939 AEMC 2012, *Rule Determination National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012*, 2 August 2012, p. 19

> *…NSPs should be provided the opportunity to recover their efficient costs in those limited circumstances where insurance is limited or not available on commercial terms and self-insurance is not appropriate. Not to do so would, over the long term, be likely to affect the efficient investment in, and efficient operation of, those networks. This is because, NSPs that cannot recover their efficient costs are reluctant to invest in their networks.*
>
> *… This should; [sic] however, be limited to instances where efficient costs are incurred because unforeseen costs arise as a result of events outside an NSP's control.*

The application of ActewAGL Distribution's revised proposed general pass through event would enable ActewAGL Distribution to recover its efficient costs of events that were unforeseen and outside its control, in circumstances where, at the time of submission of this revised regulatory proposal, insurance was limited or not available on commercial terms and self insurance was not appropriate. As recognised by the AEMC, this is necessary if ActewAGL Distribution is to be provided with a reasonable opportunity to recover its efficient costs and, thus, to be provided with the incentives for efficient investment in, and the efficient operation of, its network that are the bedrock of the regulatory regime. By contrast, a decision by the AER not to apply ActewAGL Distribution's revised proposed general pass through event in the subsequent regulatory period would, as noted by the AEMC, be likely to preclude ActewAGL Distribution from recovering its efficient costs and, thus, adversely affect efficient investment in, and the efficient operation of, its network, to the detriment of the achievement of the NEO and inconsistently with the RPPs.

As discussed in section 11.2.1 above, in making its decision on ActewAGL Distribution's revised proposed general pass through event, the AER must make the decision that it is satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree and take into account the RPPs.

While the nominated pass through events are only mandatory considerations and not preconditions to the acceptance by the AER of a nominated pass through event,[941] ActewAGL Distribution further observes that its revised proposed general pass through event is consistent with those considerations.

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[940] AEMC 2012, *Rule Determination National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012*, 2 August 2012, p. 18

[941] The legal character of the nominated event pass through considerations is evident from clause 6.5.10(b) of the Rules and is affirmed by the relevant Rules extrinsic material: see AEMC 2012, *Rule Determination National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012*, 2 August 2012, p. 20

In concluding in its draft decision that the nature or type of a general pass through event cannot be clearly identified at the time of making ActewAGL Distribution's distribution determination for the subsequent regulatory period, the AER provides no explanation for the basis of this view. In any event, paragraphs (1) to (5) of the revised definition of the proposed general pass through event particularise in some detail the nature or type of such an event. Specifically, the revised definition of the proposed general pass through event provides that such an event is one that has the following characteristics:

- it is not reasonably foreseeable at the time of making the distribution determination;
- it could not be insured against on reasonable commercial terms or self insured, at that time;
- it results in ActewAGL Distribution incurring higher or lower costs in providing direct control services;
- it could not have been prevented nor the costs thereof substantially mitigated by ActewAGL Distribution; and
- it is not covered by any other category of pass through event.

It follows that the revised proposed general pass through event is consistent with paragraph (b) of the nominated pass through event considerations.

In addition, whereas the AER concludes in its draft decision that the AER cannot consider whether ActewAGL Distribution can insure against the general pass through event, paragraph (2) of the revised definition of the proposed general pass through event provides that such an event is one which could not have been insured against on reasonable commercial terms or self insured, at the time of making the distribution determination for ActewAGL Distribution for the subsequent regulatory period. It follows that the revised proposed general pass through event is consistent with paragraph (d) of the nominated pass through event considerations.

Further, paragraph (5) of the revised definition of the proposed general pass through event ensures that that event is consistent with paragraph (a) of the nominated pass through event considerations and paragraph (4) of that revised definition ensures that that event is consistent with paragraph (c) of those considerations.

Finally, ActewAGL Distribution queries whether consistency in the AER's approach to assessing nominated pass through events across its determinations where possible is properly considered by the AER to be a nominated pass through event consideration in accordance with paragraph (e) of those considerations. The AER has not notified NSPs generally that this is to be a nominated pass through event consideration, as is required by paragraph (e) if a matter the AER considers relevant is to constitute a nominated pass through event consideration. In any event, consistency in the AER's approach to assessing nominated pass through events should be a product of the AER's application of the NEO, RPPs and the nominated pass through event considerations specified in paragraphs (a) to (d). It is not a matter that is, of itself, relevant to the assessment of whether the acceptance of a nominated pass through event would promote the relevant statutory objects and thus permissibly notified to NSPs and considered by the AER pursuant to paragraph (e) of the nominated pass through event considerations.

It follows from the above that the correct and reasonable decision is for the AER to accept ActewAGL Distribution's revised proposed general pass through event.

Additional proposed terrorism and natural disaster events

As a consequence of the revisions to its proposed definition of the general pass through event necessary to address the AER's draft decision in respect of that proposed event (which revisions limit the scope of that proposed event), ActewAGL Distribution further proposes in this revised proposal that a terrorism event and a natural disaster event of the kind accepted by the AER in its Ausgrid draft decision[942] apply to ActewAGL Distribution in the subsequent regulatory period in addition to its revised proposed general pass through event.

ActewAGL Distribution, like Ausgrid, will be exposed to the risks associated with these events and unable to reasonably prevent their occurrence or substantially mitigate their cost impacts. Specifically, with respect to its proposed terrorism event, ActewAGL Distribution observes that:

- like Ausgrid, ActewAGL Distribution has a range of measures in place to prevent acts of terrorism affecting its operations, or mitigate the impacts of such an event if one should occur. These measures are based on industry best practice and recommended government measures for a terrorism alert level of HIGH. ActewAGL Distribution has an ongoing operational security risk management program to meet its obligations in relation to infrastructure security, in particular in regards to government determined critical infrastructure. The activities that we undertake to ensure the security of our assets include:
    - Regular security patrols (twice daily and on alarm activation);
    - Intruder detection systems;
    - CCTV systems;
    - All alarms monitored ;
    - Regular preventative maintenance on security systems;
    - High security weldmesh fencing around critical infrastructure;

[942] AER 2014, Draft decision Ausgrid distribution determination 2015-16 to 2018-19, Attachment 15: Cost pass through, pp. 15-14 to 15-15

- o Bi-annual or as required review and creation of Security Management Plans based on ISO 31000 and HB 167 Security Risk Management;
- o Detailed security standards;
- o Comprehensive security frameworks, policies, and procedures;
- o Security awareness training for all staff; and
- o Participation in joint security exercises and activities at both the federal and local government level.

- the AER's conclusion in the Ausgrid draft decision that the commercial market for insurance in Australia is insufficient to cover demand is equally applicable to ActewAGL Distribution.[943];
- like Ausgrid, ActewAGL Distribution has the option of self-insuring but, as the AER concludes in the Ausgrid draft decision,[944] the relative infrequency and potentially high costs of terrorism events create significant challenges for self-insurance for this type of risk, there is limited data on the basis of which to calculate a credible self-insurance premium and taking out further insurance would likely be inefficient and result in an unnecessary cost increase to customers; and
- as the AER concludes in the Ausgrid draft decision in respect of Ausgrid,[945] while there may be some overlap between an insurance cap event and the terrorism event, ActewAGL Distribution may incur costs as a result of a terrorism event which an insurance policy would not ordinarily cover and ActewAGL Distribution's proposed definition for the terrorism event set out below (being based on the AER's definition) will assist in avoiding overlap.

With respect to its proposed natural disaster event, ActewAGL Distribution observes that:

- like Ausgrid, ActewAGL Distribution has a range of measures in place to mitigate the impacts of a natural disaster event should one occur such as:

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[943] AER 2014, Draft decision Ausgrid distribution determination 2015-16 to 2018-19, Attachment 15: Cost pass through, p. 15-12

[944] AER 2014, Draft decision Ausgrid distribution determination 2015-16 to 2018-19, Attachment 15: Cost pass through, p. 15-12

[945] AER 2014, Draft decision Ausgrid distribution determination 2015-16 to 2018-19, Attachment 15: Cost pass through, p. 15-12

- In the event of any type of business interruption event (bushfire, terrorism, cyber-attack etc), ActewAGL Distribution has in place a suite of plans that are designed to both manage all aspects of the incident, as well as ensure that it is meeting obligations under the Utilities act. These plans are exercised at least annually, and while they cover any incident type. Bushfires are considered ActewAGL Distribution's highest risk and as such, testing of ActewAGL Distribution's bushfire response management is undertaken annually. In accordance with ActewAGL Distribution's business interruption management corporate procedure ActewAGL Distribution has the following plans in place: Crisis Management Plans, Emergency Management Plans, Divisional Business Continuity Plans and IT Disaster Recovery Plans.
- Risk management methodology based on ISO 31000 Risk Management. ActewAGL Distribution assesses each of its specific risks in accordance with corporate procedures based on ISO 31000, using task specific tools and approved techniques. The improved understanding of bushfire risks that comes from using this approach underpins ActewAGL Distribution's asset and risk management activities and encompasses both prevention and mitigation
- ActewAGL Distribution's bushfire prevention and mitigation strategies include:
    - Development and adherence to ActewAGL Distribution's bushfire risk management plan.
    - Identification of bushfire risks – ActewAGL Distribution has a spatial risk assessment that determines the likely fire intensity of a fire started at that point. This enables targeted maintenance based on risk.
    - Improving the standards for electricity assets. ActewAGL Distribution implements an audit regime to ensure compliance with internal and industry standards and codes. ActewAGL Distribution has continued to work on asset hardening and resilience work through common energy utility practices such as spreaders, dampers, aerial bundled cable, auto reclosers etc targeted as far as possible on bushfire abatement zones and high risk areas. This forms part of ActewAGL Distribution's repex program for 2014-19 and is discussed in section 4.5.4 of this revised proposal.
    - Prudent maintenance procedures aimed at mitigating bushfire risks. This includes routine above ground inspections carried out at intervals carried out either aerially or from the ground to maximise benefits and reduce costs. ActewAGL Dist ribution has instigated a 'bushfire preparedeness index' to ensure all works are completed prior to the

declared bushfire period, including inspection, asset and vegetation maintenance, staff readiness and community engagement.

    - Specific operational procedures for times of very high fire danger. ActewAGL Distribution staff and contractors follow purpose designed work procedures and precautions during the declared bushfire period and total fire bans. Notification of total fire ban days is via SMS and email from our Network Control Room. In addition, protection settings on certain equipment are altered during very high fire danger by switching the re-close function on nominated high voltage distribution and sub transmission feeders from automatic to manual.
    - Management of safe vegetation clearances. To help prevent the possibility of trees or bushland vegetation causing bushfires, we manage vegetation safety clearances on our network. This is further discussed in the EHSQ step change in Chapter 3.
    - Working with other agencies to ensure a coordinated approach to bushfire risk management. ActewAGL Distribution works closely with ACT Government agencies in regards to all emergency issues, and is an active member and participant in the ACT's Security and Emergency Management Senior Officials Group (SEMSOG) and its supporting organisations.

- like Ausgrid, ActewAGL Distribution currently has an appropriate level of commercial insurance for natural disasters within its Property Policy and General Liability Policy.[946] However, this insurance has limitations and exclusions which may mean that not all costs associated with a natural disaster event are covered and taking out further insurance would likely be inefficient and result in an unnecessary cost increase to customers.
- like Ausgrid, ActewAGL Distribution has not included a self insurance amount for natural disasters in its forecast opex proposal as, in the event of a major natural disaster, it would be unlikely to be in a position to pool enough risk to cover the cost impacts from such an event; and

[946] Both of these policies are detailed in sheet 2.15 of attachment A3 Regulatory reset (5 year) RIN report template – Consolisated information – confidential.

- as the AER concludes in the Ausgrid draft decision in respect of Ausgrid,[947] while there may be some overlap between an insurance cap event and a natural disaster event, ActewAGL Distribution may incur costs as a result of a natural disaster event which an insurance policy would not ordinarily cover.

ActewAGL Distribution further observes that the potential for overlap between its revised proposed general pass through event and its proposed terrorism event and natural disaster event is addressed by paragraph (5) of its revised proposed definition of the general pass through event. This paragraph (5) provides that an event will not be a general pass through event if it is covered by any other event specified as a pass through event in ActewAGL Distribution's distribution determination for the subsequent regulatory period.

It follows from the above that the AER's conclusion (implicit in its decision to accept a terrorism event and a natural disaster event in the Ausgrid draft decision[948]) that the application of a terrorism event and a natural disaster event in the subsequent regulatory period will contribute to the achievement of the NEO and is consistent with the nominated pass through event considerations is equally applicable to ActewAGL Distribution. ActewAGL Distribution has based its proposed definitions for its proposed terrorism event and natural disaster event on the definitions of these events accepted by the AER in its draft decision for Ausgrid.[949] ActewAGL Distribution has, however:

- removed the word 'materially', as for a positive or negative change event (as defined in the Rules) to occur the cost increase or decrease respectively resulting from the relevant event must be material within the meaning of the Rules' definition of 'materially'; and
- amended the AER’s proposed notes appended to the definition of each of these events, which state which factors the AER will have regard to in assessing a pass through application in respect of one of these events, to clarify that the AER will consider those matters under clause 6.6.1(j) of the Rules.

ActewAGL Distribution therefore proposes the following definition for the terrorism event and the natural disaster event (with the revisions proposed by ActewAGL Distribution to the AER's

[947] AER 2014, Draft decision Ausgrid distribution determination 2015-16 to 2018-19, Attachment 15: Cost pass through, p. 15-13

[948] AER 2014, Draft decision Ausgrid distribution determination 2015-16 to 2018-19, Attachment 15: Cost pass through, pp. 15-11 to 15-13

[949] AER 2014, Draft decision Ausgrid distribution determination 2015-16 to 2018-19, Attachment 15: Cost pass through, pp. 15-14 to 15-15

definitions of these events in its Ausgrid draft decision shown in hard mark ups and green shading):

A terrorism event occurs if:

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

Note: In assessing a terrorism event pass through application under rule 6.6.1(j), the AER will have regard to, amongst other things:

i. whether ~~Ausgrid~~ ActewAGL Distribution has insurance against the event,

ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event, and

iii. whether a declaration has been made by a relevant government authority that a terrorism event has occurred

iv. the extent to which a prudent provider could reasonably mitigate the impact of the event.

A natural disaster event occurs if:

Any major fire, flood, earthquake or other natural disaster occurs during the 2015-19 regulatory control period and ~~materially~~ increases the costs to ~~Ausgrid~~ ActewAGL Distribution in providing direct control services, provided the fire, flood or other event was not a consequence of the acts or omissions of the service provider

The term 'major' in the above paragraph means an event that is serious and significant. It does not mean material as that term is defined in the Rules (that is 1 per cent of the DNSP's annual revenue requirement for that regulatory year).

Note: In assessing a natural disaster event pass through application, the AER will have regard to under rule 6.6.1(j), amongst other things:

i. whether ~~Ausgrid~~ActewAGL Distribution has insurance against the event,

ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event,

iii. whether a relevant government authority has made a declaration that a natural disaster has occurred, and

iv. the extent to which ba prudent NSP could reasonably mitigate the impact of the event.

12 Incentive schemes

12.1 Introduction

Clause 6.12.1(2)(i) and (9) of the Rules provides that the constituent decisions by the AER on which the distribution determination for ActewAGL Distribution for the subsequent regulatory period is predicated includes (amongst others):

- a decision on the ActewAGL Distribution's current building block proposal in which the AER either approves or refuses to approve the ARR for ActewAGL Distribution, as set out in the building block proposal, for each regulatory year of the regulatory control period; and
- a decision on, relevantly, 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 (DMIS),

  is to apply to ActewAGL Distribution.

Clause 6.4.3 of the Rules provides for the ARR for each regulatory year of a regulatory control period to be determined using a building block approach, under which the constituent building blocks include the revenue increments or decrements (if any) for that year arising relevantly from the application of the EBSS, CESS, STPIS and DMIS as referred to in clauses 6.5.8, 6.5.8A, 6.6.2 and 6.6.3 of the Rules. However, as the CESS and the STPIS did not apply to ActewAGL Distribution in the 2009-14 regulatory control period or the transitiona regulatory period, there are no revenue increments or decrements for the subsequent regulatory period arising from the application of the CESS or the STPIS during a previous regulatory control period.

This Chapter 12 discusses the part of the AER's draft decision in respect of the EBSS, CESS, STPIS and DMIS in turn. In so doing, ActewAGL Distribution responds to the following parts of the AER's draft decision as follows:

- Attachment 9 which addresses the EBSS is responded to in section 12.2;
- Attachment 10 which addresses the CESS is responded to in section 12.3;
- Attachment 11 which addresses the STPIS is responded to in section 12.4; and
- Attachment 12 which addresses the DMIS is responded to in section 12.5.

The AEMC has noted while the incentive properties of each of the schemes is important, the more important consideration is the overall effect of the package of the incentive mechanisms. Accordingly, this Chapter discusses the interactions between each of the schemes as appropriate to ActewAGL Distribution's response.[950]

12.2 EBSS

12.2.1 Overview

This section 12.2 responds to the AER's draft decision in respect of the EBSS set out in Attachment 9 to its draft decision.

ActewAGL Distribution proposed a total EBSS carryover amount of -$19.6 million ($2013/14) (EBSS Penalty) be subtracted from its regulated revenue in the 2014–19 period by virtue of the application of the EBSS that applied to ActewAGL Distribution in the 2009-14 regulatory control period, namely the EBSS developed for the ACT and NSW DNSPs' 2009 distribution determinations published by the AER in February 2008 (Historical EBSS).[951]

ActewAGL Distribution proposed for the 2014-19 period that the EBSS published by the AER on 29 November 2013 which is stated to apply to electricity transmission and distribution determinations for regulatory control periods commencing after November 2013 (Current EBSS)[952] apply to it consistent with the AER's proposal in its Stage 2 Framework and Approach—ActewAGL, January 2014 (Stage 2 F&A Paper)[953] but with two modifications as follows:

- the exclusion of uncontrollable costs; and
- setting the EBSS allowance for the transitional regulatory period equal to the actual spend in that year.[954]

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[950] See, for example, AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, 16 November 2006, p. 92

[951] AER 2008, Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations, February 2008

[952] AER 2013, Better Regulation, Efficiency Benefits Sharing Scheme for Electricity Network Service Providers, November 2013 (Version 2)

[953] AER 2014, *Stage 2 Framework and approach ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, January 2014, p. 27

[954] The AER determined that the EBSS would apply to ActewAGL Distribution in the 2014–15 period in its transitional regulatory period Determination

While the AER accepts ActewAGL Distribution's calculation of the EBSS Penalty, in the draft decision the AER determines that it will not apply the EBSS Penalty to ActewAGL Distribution. It takes this position as the Historical EBSS was intended to work in conjunction with a revealed cost forecast approach, and the AER's draft decision in respect of opex is to not use that forecast approach for the 2014–19 period. The AER therefore considers it would not be consistent with the intended operation of the Historical EBSS, and it would not be implementing the Historical EBSS in accordance with the Rules, if the AER were to apply the EBSS Penalty.[955]

Further, the AER's draft decision is that no opex will be subject to the Current EBSS during the 2014–19 regulatory period. Accordingly, the AER did not accept or reject ActewAGL Distribution's proposed modifications to the Current EBSS.

The AER takes this position because it recognises that the application of an EBSS in one regulatory control period is intrinsically linked to the adoption of a revealed cost forecasting approach in the next[956] and considers that it is uncertain whether the AER will rely on ActewAGL Distribution's revealed costs in the 2014-19 period in forecasting its efficient opex in the future.[957]

The AER considers that if it applied the Current EBSS in the 2014–19 period but then did not rely on revealed costs to set forecast opex in the next regulatory control period, there will be some potentially perverse outcomes, in that if it continues to make incremental efficiency losses, ActewAGL Distribution would receive significant negative EBSS carryovers as well as a benchmark opex allowance. The AER acknowledges that such an outcome is not consistent with the application of the Current EBSS nor with the Rules' EBSS requirements.[958]

The AER also considers that ActewAGL Distribution will already face an incentive to make efficiency improvements while its actual opex is more than that of a benchmark efficient service

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[955] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-7

[956] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-8

[957] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, pp. 9-7 and 9-11

[958] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-12

provider and therefore the AER does not need to apply the Current EBSS to further strengthen those incentives.[959]

It is relevant to this section 12.2 to reiterate that ActewAGL Distribution rejects the AER's draft decision on forecast opex (see Chapter 3 of this revised regulatory proposal).

ActewAGL Distribution also rejects the draft decision on EBSS because in deciding not to rely on ActewAGL Distribution's revealed costs in forecasting its opex and, in that context, deciding not to apply the Current EBSS to ActewAGL Distribution:

- in the 2015-19 period on the basis that:
    - it is uncertain whether and to what extent the AER will rely on ActewAGL Distribution's revealed costs for the 2014-19 period in forecasting opex in the future (see Section 12.2.6); and
    - it is unnecessary to further strengthen ActewAGL Distribution's incentive to make efficiency gains in that period (see section 12.2.6),

  the AER has made a decision that is unreasonable in all the circumstances;
- in the 2014-2019 period, the AER has made a decision that is not in accordance with the NEO because it does not provide ActewAGL Distribution with effective incentives in order to promote economic efficiency (see sections 0 and 0). As the AER's constituent decision on how the EBSS is to apply to ActewAGL Distribution in the subsequent regulatory period is intended to promote the efficiency objectives of the NEO, it follows that the AER's decision not to apply any EBSS does not contribute to the achievement of the NEO and, accordingly, is not compliant with the AER's obligation under section 16(1)(d) of the NEL to make the NEO preferable decision.

ActewAGL Distribution therefore maintains its position in its regulatory proposal for the subsequent regulatory period (in combination with maintaining its view that the AER should continue to use a revealed cost forecast approach in setting ActewAGL Distribution's opex allowance as set out in Chapter 3):

- that the Historical EBSS apply to it with the effect that the EBSS Penalty be subtracted from its regulated revenue in the 2014–19 period;
- that the Current EBSS apply to it in the 2014–19 period but with the two modifications covered below to the AER’s approach discussed above.

[959] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-12

In the event the AER maintains its draft decision, and makes a final decision to set forecast opex on a basis other than revealed costs and to not apply the Current EBSS, then ActewAGL Distribution accepts the AER's draft decision that no EBSS Penalty be applied[960] and contends that:

- its revenue allowance should be adjusted for the 2014-2019 period to ensure that ActewAGL Distribution only bears 30 per cent of the opex cost overrun from the 2009-14 period rather than 100 per cent. As discussed in Chapter 3 such an adjustment would form part of the glide path that ActewAGL Distribution contends the AER must implement; and

- the AER must implement a EBSS that is designed to operate with the AER's new approach to set forecast opex.

12.2.2 The relevant legal and regulatory framework for the EBSS

The NEO and the RPPs

The AER must perform or exercise a function or power under the NEL or the Rules that relates to the making of a distribution determination in a manner that will or is likely to contribute to the achievement of the NEO (NEL, section 16(1)(a) and section 2(1) definition of 'AER economic regulatory function or power'). Further, in making a distribution determination, if there are 2 or more decisions that will or are likely to contribute to the achievement of the NEO, the AER must make the decision that it is satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree (NEL, section 16(1)(d) and sections 2(1) and 71A definitions of 'reviewable regulatory decision').

The NEO is set out in section 7 of the NEL and reads as follows:

> *The objective of this Law 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-*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system.*

Economic efficiency, including efficient investment in the system with which the provider provides services, is thus the ultimate objective of the regulatory regime established by the NEL

[960] See section 3.4.4.4.

and Rules.[961] The interests of consumers of electricity with which the NEO is concerned are those in obtaining lower prices (than would otherwise be the case), increased quality, safety, reliability and security of supply and the increased reliability, safety and security of the national electricity system.[962]

In addition, the AER must take into account the RPPs when exercising a discretion in making those parts of a distribution determination relating to direct control network services (NEL, section 16(2)(a)). The RPPs in section 7A can be taken to be consistent with and to promote the objectives in section 7. The principles are themselves stated normatively in the form of what is intended to be achieved.[963]

The RPPs are set out in section 7A of the NEL and relevantly include that:

> *A regulated 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 –*
>
> *(a) Efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and*
>
> *(b) The efficient provision of electricity network services; and*
>
> *(c) The efficient use of the distribution system or transmission system with which the operator provided direct control network services.*

Constituent decisions on application of the EBSS

Clause 6.12.1(2)(i) and (9) of the Rules provides that the constituent decisions by the AER on which the distribution determination for ActewAGL Distribution for the subsequent regulatory period is predicated include (amongst others):

- a decision on the ActewAGL Distribution's current building block proposal in which the AER either approves or refuses to approve the ARR for ActewAGL Distribution, as set out in the building block proposal, for each regulatory year of the regulatory control period; and

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[961] See, for example, *Application by Energy Australia and Others (including corrigendum dated 1 December 2009)* [2009] ACompT 8, at [79]-[81], including in particular the Tribunal's observation at [81] that the achievement of the efficiency objectives is the very purpose of the regulatory regime

[962] *Re Seven Network Limited (No 4)* (2004) ACompT 11 at [120], in discussing the objective of Part XIC of the *Trade Practices Act 1974* (Cth) (TPA) (now the *Competition and Consumer Act 2010* (Cth) (CCA)), being the long term interests of end-users', on which the NEO was modelled

[963] *Application by Energy Australia and Others* [2009] ACompT 8 (with Corrigendum) at [79]

- a decision on how any applicable EBSS is to apply to ActewAGL Distribution.

The ARR for ActewAGL Distribution for each regulatory year of a regulatory control period must be determined using a building block approach, under which the building blocks include, amongst other things, the revenue increments or decrements (if any) for each regulatory year of the regulatory control period arising from the application of the EBSS referred to in clause 6.5.8 of the Rules during the previous regulatory control period (clause 6.4.3(a)).

Clause 11.56.4(c) of the Rules provides that, for the purposes of making the distribution determination for ActewAGL Distribution for the subsequent regulatory period, the AER must determine the ARR for ActewAGL Distribution for each regulatory year of the subsequent regulatory period in accordance with current Chapter 6 and as if the subsequent regulatory period comprised the transitional regulatory period (as the first regulatory year of the subsequent regulatory period) and all of the regulatory years of the subsequent regulatory period (as the remaining regulatory years of the subsequent regulatory period), and the transitional regulatory period were not a separate regulatory control period. That clause further states, for the avoidance of doubt, that it requires the AER to determine a notional ARR for the regulatory year that comprises the transitional regulatory period. It follows that, in making the distribution determination for the subsequent regulatory period for ActewAGL Distribution, the AER must determine the revenue increments or decrements (if any) for the transitional regulatory period, as well as the subsequent regulatory period, arising from the application of the EBSS during the 2009-14 regulatory control period.

Clause 11.56.4(b) to (f) of the Rules provides for the application of specified provisions of current Chapter 6 of the Rules on the basis that the transitional regulatory period is to be treated as either the last regulatory year of the 2009-14 regulatory control period or the first regulatory year of the subsequent regulatory period. Clause 11.56.4(g), in turn, provides that nothing in clause 11.56.4 has the effect of actually rendering the transitional regulatory period as the first regulatory year of the subsequent regulatory period and, except for the purposes of the application of paragraphs (b) to (f) in accordance with their terms, the transitional regulatory period must be treated as a regulatory control period that is separate to the subsequent regulatory period.

Clause 6.12.1(9) of current Chapter 6, which provides for the making of the constituent decision on how any applicable EBSS is to apply to ActewAGL Distribution, is not referred to in paragraphs (b) to (f) of clause 11.56.4. It follows that, in making the distribution determination for ActewAGL

Distribution for the subsequent regulatory period, the AER's decision is in respect of how any applicable EBSS is to apply to ActewAGL Distribution in the subsequent regulatory period.[964]

Development and implementation of the EBSS

Clause 6.5.8(a) of the Rules requires that the AER develops and publish an incentive scheme or schemes, the EBSS, that provide for a fair sharing between DNSPs and distribution network users of:

- the efficiency gains derived from the opex of DNSPs for a regulatory control period being less than; and
- the efficiency losses derived from the opex of Distribution Network Service Providers for a regulatory control period being more than,

the forecast opex accepted or substituted by the AER for that regulatory control period.

Clause 6.5.8 (c) lists the mandatory considerations that the AER must have regard to in developing and implementing an EBSS. These are as follows:

- the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs;
- the need to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce opex;
- the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses;
- any incentives that DNSPs may have to capitalise expenditure; and
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

[964] Clause 11.56.3(a)(4) of the Rules required the distribution determination made by the AER for ActewAGL Distribution for the TRP to specify the EBSS that applied to ActewAGL Distribution under its distribution determination for the 2009-14 regulatory control period applies to ActewAGL Distribution in the TRP subject to such modifications as are set out in the framework and approach paper that is published in respect of the SRP for ActewAGL Distribution. Clause 11.56.3(h)(3) of the Rules provides that a framework and approach paper that is published in respect of the SRP for ActewAGL Distribution may specify in relation to the distribution determination for the TRP, the modifications to be made to an incentive scheme referred to in paragraph (a)(4)

12.2.3 Previous relevant decisions of the AER

The AER's *Australian Capital Territory distribution determination 2009-10 to 2013-14* dated 28 April 2009 (**2009 Final Decision**) includes the constituent decision that the EBSS to apply to ActewAGL in the 2009-14 regulatory control period was the Historical EBSS.[965]

On 29 November 2013, the AER published its Current EBSS which it stated to apply to electricity transmission and distribution determinations for regulatory control periods commencing after November 2013 (in accordance with clause 6.5.8(d) of the Rules).

The AER's Stage 2 F&A Paper[966] provides for modifications to the Historical EBSS as it is to apply in the transitional regulatory period and the proposed approach to the application of the Current EBSS in the 2015-19 period as follows:

> We propose to apply to AAD:
>
> - Version 1 of [the Historical EBSS] in the 2014-15 transitional control period with modifications to align it with version 2 of [the Current EBSS]. In summary, this will include:
>   - the formulae for calculating efficiency gains and losses
>   - our approach to adjustments to forecast or actual opex when calculating carryover amounts
>   - our approach to determining the carryover period.
> - [The Current EBSS] in the 2015-19 subsequent regulatory control period.

In accordance with clause 11.56.3(a)(4) of the Rules, the AER's placeholder determination for ActewAGL Distribution for the transitional regulatory period provides that:

> The AER determines that the…EBSS…that will apply to ActewAGL for the transitional regulatory control period is that applied to ActewAGL in the current regulatory control period, with modifications to align it with version 2 of the EBSS and applied as if the transitional regulatory control period was the first year of the subsequent regulatory control period. This is consistent with the Stage 2 framework and Approach paper,
>
> (**TRP EBSS Decision**).

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[965] AER 2008, Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations, February 2008

[966] AER 2014, *Stage 2 Framework and approach ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, January 2014, p. 27

12.2.4 ActewAGL Distribution's proposal

Application of the EBSS Penalty in 2014-19 ARRs

In ActewAGL Distribution's regulatory proposal for the subsequent regulatory period it estimated the carryover amounts for the 2014-19 period arising from the application of the Historical EBSS in the 2009–14 regulatory control period as set out in Table 12.1.

Table 12.1 Opex in 2009-14 subject to the Historical EBSS and carryover effects for 2014/19

$ million	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*
Forecast opex for EBSS purposes, $08/09	48.5	49.0	50.0	51.7	n/a
Forecast opex for EBSS purposes, $13/14	55.7	56.3	57.4	59.4	n/a
Total actual opex, $13/14	68.3	79.9	91.2	98.7	n/a
Excluded costs, $13/14	-11.1	-14.4	-21.1	-28.5	n/a
Opex subject to the EBSS, $13/14	57.2	65.5	70.1	70.2	n/a
Incremental gain/loss ($2013/14)	-1.5	-7.7	-3.5	1.9	n/a
$ million (2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Carryover effect	-10.7	-9.2	-1.5	1.9	-
Allocated to distribution	-9.4	-8.1	-1.3	1.7	
Allocated to transmission	-1.3	-1.2	-0.2	0.2	

ActewAGL Distribution therefore proposed a total EBSS carryover amount of -$19.6 million ($2013/14) be subtracted from its regulated revenue in the 2014–19 period, being the EBSS Penalty.

Application of the EBSS in the 2014-19 period

Further, ActewAGL Distribution proposed for the 2014-19 period that the Current EBSS apply to it consistent with the AER's proposal in its Stage 2 F&A Paper[967] but with two modifications as follows:

- the exclusion of uncontrollable costs; and
- setting the EBSS allowance for the transitional regulatory period equal to the actual spend in that year (being the way in which ActewAGL Distribution proposed that the AER should practically apply its transitional regulatory period EBSS Decision).

[967] AER 2014, *Stage 2 Framework and approach ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, January 2014, p. 27

12.2.5 AER draft decision

Application of the EBSS Penalty in 2014-19 ARRs

The AER accepts ActewAGL Distribution's calculation of the EBSS Penalty, namely -$19.6 million ($2013/14)[968]. However, the AER's draft decision is that it will not apply the EBSS carryover amounts to ActewAGL Distribution arising from the application, during the 2009–14 regulatory control period, of the Historical EBSS.

The AER concludes that the EBSS is 'intrinsically linked' to a revealed cost forecasting approach for opex.[969] The AER states that, as the Historical EBSS was intended to work in conjunction with a revealed cost forecast approach, and the AER's draft decision in respect of opex is to not use that forecast approach for the 2014–19 period, it would not be consistent with the intended operation of the Historical EBSS, and it would not be implementing the Historical EBSS in accordance with the Rules, if the AER were to apply the EBSS Penalty.[970]

The AER notes that, if it applied both the EBSS Penalty and a benchmark opex allowance in accordance with its draft decision on forecast opex in respect of the 2014-19 period, it would mean that the efficiency losses ActewAGL Distribution made during the 2009–14 regulatory control period would not be shared fairly with consumers as intended by the Rules and the Historical EBSS. Instead, ActewAGL Distribution would carry a greater share of efficiency losses than was intended when the AER decided to apply the Historical EBSS prior to the start of the 2009–14 regulatory control period.[971]

In so concluding, the AER conveys that it makes this decision only because of the change in its opex forecasting approach.[972]

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[968] AER, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-9

[969] AER, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-8

[970] AER, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-7

[971] AER, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-10

[972] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-10

Application of the EBSS in the 2014-19 period

The AER's draft decision is that no opex will be subject to the Current EBSS during the 2014–19 period. Accordingly, the AER did not accept or reject ActewAGL Distribution's proposed modifications to the Current EBSS.

The AER takes this position because it recognises that the application of an EBSS in one regulatory control period is intrinsically linked to the adoption of a revealed cost forecasting approach in the next[973] and considers it is uncertain whether the AER will rely on ActewAGL Distribution's revealed costs in the 2014-19 period in forecasting its efficient opex in the future.[974] This is, in turn, because the AER intends in the future to apply a revealed costs approach only where it considers that a DNSP's revealed costs compares well to those of a benchmark efficient service provider and ActewAGL Distribution will only have about three years to improve its opex performance relative to that of the benchmark provider.[975]

The AER considers that if it applies the Current EBSS in the 2014–19 period but then does not rely on revealed costs to set forecast opex in the next regulatory control period, there will be some potentially perverse outcomes.[976] Specifically, if it continues to make incremental efficiency losses, ActewAGL Distribution would receive substantial negative EBSS carryovers as well as a benchmark opex allowance. The AER acknowledges that such an outcome is not consistent with the intent of the Current EBSS nor with the Rules' EBSS requirements.

The AER also considers that ActewAGL Distribution will already face an incentive to make efficiency improvements while its actual opex is more than that of a benchmark efficient service provider and therefore the AER does not need to apply the Current EBSS to further strengthen those incentives.[977]

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[973] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-8

[974] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-7 and 9-11

[975] AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-11 to 9-12

[976] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-12

[977] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-12

Finally, the AER also observes that, as it had previously determined that the Current EBSS would apply to ActewAGL Distribution in the transitional regulatory period as if the transitional regulatory period were the first year of the subsequent regulatory period, the effect of its EBSS draft decision is that no opex incurred during the 2014-19 period will therefore be subject to the EBSS.[978]

12.2.6 ActewAGL Distribution's response to the draft decision

In this section ActewAGL Distribution responds to the AER's draft decision, in light of the draft decision in respect of opex. As the AER acknowledges, the inter-relationship between the AER's adoption of a forecasting approach and the application of an EBSS means that ActewAGL Distribution's response to the draft decision in respect of opex (in Chapter 3 of this revised regulatory proposal) is also relevant to the matters outlined in this section.

Overview

In making the decision not to apply the Current EBSS to ActewAGL Distribution in the subsequent regulatory period, on the basis that:

- it is uncertain whether and to what extent the AER will rely on ActewAGL Distribution's revealed costs for the 2014-19 period in forecasting opex in the future; and
- that it is unnecessary to further strengthen ActewAGL Distribution's incentive to make efficiency gains in that period, having regard to the AER's conclusion that ActewAGL Distribution's actual opex was materially inefficient in the 2009-14 regulatory control period and resultant implicit conclusion that ActewAGL Distribution has not responded to the additional incentives for efficiency created by the application of the Historical EBSS in that period, the AER makes an error or errors of fact material to the making of its decision and/or makes a decision that is unreasonable in all the circumstances.

In addition, the draft decision not to the apply the Current EBSS in the 2014-2019 period is not in accordance with the NEO by virtue of the fact that it does not provide ActewAGL Distribution with effective incentives in order to promote economic efficiency. In particular, the AER has erred in two aspects of the underlying reasoning of its draft decision as follows:

- the AER incorrectly finds that ActewAGL Distribution has not responded to the additional incentives for efficiency created by the application of the Historical EBSS in the 2009-14 period;

[978] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, see footnote 2 on p. 9-7

- the AER incorrectly finds the draft decision ensures that ActewAGL Distribution does not share efficiency losses in an unintended way.

The AEMC has made it clear that economic regulation needs to provide (amongst other things) effective incentives to encourage DNSPs to operate their distribution systems efficiently.[979] The AER's draft decision fails to provide such incentives.

ActewAGL Distribution contends therefore that, in relying upon these findings, the AER makes an error or errors of fact material to the making of its decision and/or makes a decision that is unreasonable in all the circumstances.

To assist ActewAGL Distribution to respond to the draft decision on forecast opex and on the EBSS, ActewAGL obtained an expert report prepared by HoustonKemp that is included in Attachment C1. In summary, HoustonKemp's views are:

> *the AER's proposed approach to setting the opex allowance and its associated abandonment of the EBSS will have profound effects on the efficiency incentives for a DNSP. The proposed changes give rise to incentive arrangements that are wholly inconsistent with the principles set out in clause 6.5.8(c) of the rules. The deficiencies I have identified show that the incentive arrangements sitting within the combination of measures proposed by the AER are deeply flawed. In my opinion, the draft decision gives insufficient attention to the long term incentives its create, and undermines the existing regulatory framework that, with the introduction of the CESS, would otherwise have aligned the incentives on a DNSP to deliver long term efficiency.*[980]

The AER's conclusion that it is uncertain whether and to what extent it will rely on ActewAGL Distribution's revealed costs in forecasting opex in the future

Given the AER's statement that it does not intend, in future, to use a revealed cost approach to forecasting opex where a DNSP's opex in the base year is not efficiently incurred, it will always be uncertain at the time of making a distribution determination whether and to what extent the AER will rely on revealed costs in forecasting opex for the DNSP in making its next distribution determination. The uncertainty relied on by the AER in making its draft decision is not unique to ActewAGL Distribution or to the making of the final decision.

This conclusion is an irrelevant consideration and accordingly, the AER cannot have regard to this matter in making its draft decision nor its final decision.

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[979] See, for example, AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, 16 November 2006, p. 92.

[980] See Attachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015, p 25

The AER's contention that its draft decision provides ActewAGL Distribution with sufficient incentives to make efficiency gains

Contrary to the AER's view, ActewAGL Distribution contends that in fact the AER's draft decision fails to provide sufficient incentives to ActewAGL Distribution to make efficiency gains. HoustonKemp's analysis provides a number of reasons for this including that the share of the benefits from outperforming the opex allowance retained by the DNSP falls through the regulatory period. In other words, the share of the benefits from outperforming the opex allowance that are retained by a DNSP falls through the regulatory period from 25 per cent (for outperformance in the first year of the regulatory control period) to 6 per cent per cent (for outperformance in the final year of the regulatory period).

The consequence of this falling incentive is to encourage a DNSP to delay any efficient reductions in opex below the benchmark levels until either:

- the first year of the regulatory period, so as to retain 25 per cent of the benefits; or
- later in a period when an EBSS would apply, so that the DNSP is able to retain 30 per cent of the efficiency gains.[981]

The draft decision also provides disincentives to make inefficiency gains as ActewAGL Distribution would receive no reward up to the point it is able to achieve the benchmark level of opex. HoustonKemp opines that:

> *…if ActewAGL were able to reduce its annual revealed opex from $69.8 million (2013/14 dollars) by $13.65 million per annum (a 20 per cent reduction in annual opex), it would face a penalty because its opex costs are still $13.65 million higher than the level set by the opex allowance.*[982]

HoustonKemp has also identified that under the draft decision:

- customers will receive a 100 per cent benefit from any cost reductions achieved during the 2014-19 period until ActewAGL Distribution has achieved the AER's operating expenditure allowance;
- if ActewAGL Distribution was to reduce operating expenditure half way toward the frontier, customers would receive 200 per cent of the overall benefit, ie, more than the cost savings actually achieved; and

[981] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015, p 23

[982] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015, p 23

- the absence of the EBSS in the 2014-2019 period means that to the extent that ActewAGL Distribution was to outperform the benchmark then it would retain less than 30 per cent of the benefits of the outperformance.[983]

HoustonKemp also notes that while a DNSP's actual opex is above the efficient level suggested by the AER's benchmarking analysis, it has a strong incentive to capitalise expenditure because:

- *the penalty for increasing capex under the CESS would be 30 cents in every additional dollar of capitalised expenditure; while*
- *the benefit of decreasing opex to the benchmark results in reduced penalty of $1 for every additional of capitalised expenditure.*[984]

The AER's implicit conclusion that ActewAGL has not responded to the additional incentives for efficiency created by the application of the Historical EBSS in the 2009-14 period

The AER's conclusion that ActewAGL Distribution's actual opex was materially inefficient in the 2009-14 regulatory control period leads to the implicit conclusion that ActewAGL has not responded to the additional incentives for efficiency created by the application of the Historical EBSS in that period. That conclusion is incorrect.

ActewAGL Distribution contends that the revealed cost approach to forecasting opex and the application of an EBSS together provide sufficient incentives for ActewAGL Distribution to continuously seek efficiency improvements over time.[985] In support of this view, HoustonKemp states that:

> *the incentives created by the [Historical] EBSS reward the DNSP for implementing opex reductions, for avoiding unnecessary increases in opex, and for not bringing forward opex… the incentives provided over the 2009-14 regulatory period – the incentives envisaged by the [Historical] EBSS – would reward a DNSP for any efficient opex reductions and penalise it for any opex inefficiencies.*[986]

[983] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015, p 21

[984] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015,, p 24

[985] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015,, p 11

[986] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015, p 13

The AER's finding that ActewAGL Distribution's actual opex in the 2012/13 base year was materially inefficient is not a reliable basis upon which to conclude that ActewAGL Distribution has not responded to the incentives under the EBSS.[987]

HoustonKemp identifies a number of plausible reasons as to why a DNSP may choose to increase its incremental operating expenditure and provides the following examples, which are discussed in more detail in turn immediately below:

- events not expected at the time of the last regulatory determination;
- to achieve future opex efficiencies; and
- to improve service performance.[988]

While ActewAGL Distribution's opex allowance is the AER's best forecast at the time of its decision, the methods the AER uses to decide efficiency losses and gains under an EBSS also sets aside many real world complexities.[989] Hence, ActewAGL Distribution's actual opex can readily be expected to differ over a five year period from that which was forecast. For example, the opex allowance is generally predicated on a forecasts of input cost escalators, which do not necessarily eventuate. ActewAGL Distribution's 2009-14 opex allowance was predicated on an estimate of labour cost escalators which was not accurate. In fact, real general labour costs in the ACT were substantially higher than that forecast.[990]

The fact the incentives created by the Historical EBSS are symmetric means that a DNSP has an incentive to incur higher opex today if it results in a sufficient fall in future opex. HoustonKemp's analysis highlights there are a number of incentives for DNSPs to incur opex today in order to achieve future opex savings, including that if the future benefits in terms of lower recurring opex outweigh the cost of the immediate increase in opex.[991]

In the 2009-14 regulatory control period the CESS did not apply and accordingly, the incentives for efficient capex declined over the regulatory control period. HoustonKemp finds this has the consequence that later in the regulatory period, the DNSP has an incentive to incur capex instead

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[987] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015, p 13

[988] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015, p 13

[989] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015, p 13

[990] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015,, p 14, see in particular Table 3 and Table 4

[991] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015, p 15, see in particular Table 5

of opex.[992] Accordingly, in the base year (2012/13), the DNSP does not have an incentive to incur opex instead of capex which further supports that ActewAGL Distribution had a strong incentive to underspend its opex allowance.

The AER's contention that its draft decision ensures that ActewAGL Distribution does not share efficiency losses in an unintended way

HoustonKemp opines that by providing DNSPs with a share of the benefits of permanent efficiency gains the ultimate reduction in the cost of providing the service will be more significant than would otherwise be the case. By virtue of that outcome, the long term interests of consumers will be enhanced.[993]

In the draft decision, the AER states that to apply the EBSS Penalty would:

> *… mean ActewAGL would carry a greater share of efficiency losses than was intended when we decided to apply the EBSS prior to the start of the 2009–14 regulatory control period.*[994]

In making this statement the AER implies that in effect allowing ActewAGL Distribution to retain the EBSS Penalty of $19.6 million, as the AER proposes, means that ActewAGL Distribution does not retain more than its intended share of the efficiency losses from the 2009-14 regulatory control period. The draft decision does not have this effect.

The AER has not recognised the fact that the draft decision in fact imposes a share of efficiency losses on ActewAGL Distribution that is materially greater than that intended when the Historical EBSS was developed. The effect of the draft decision would be to impose 100 per cent of the costs of all efficiency losses in the 2009-14 regulatory control period on ActewAGL Distribution rather than the approximate 30 per cent intended under the Historical EBSS. HoustonKemp confirms that the draft decision means that ActewAGL Distribution retains more than its intended share of the efficiency losses in that it is effectively penalised in the order of $36.7 million ($2013/14) in net present value terms. HoustonKemp concludes:

> *an unanticipated retrospective change to the regulatory framework that imposes a substantial material negative financial loss to a DNSP materially increases the regulatory risk applying to all network service providers. This cannot be consistent with the NEO…to maintain the intended*

[992] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015, p 14

[993] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015, p 11

[994] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, pp. 9-10.

sharing ratio of 30:70 in net present value terms, would require the AER to add $36.7 million (2013-14 dollars) to ActewAGL's 2014-15 revenues.[995]

A failure to make this adjustment would increase the level of uncertainty in the regulatory environment and substantially increase the level of regulatory risk. Regulatory risk increases the prospect of investors' expectations as to the return on or return of capital for a particular project not being met, and so increases ActewAGL Distribution's cost of providing capital to the detriment of the long term interests of consumers.[996] The AEMC has made it clear that economic regulation needs to provide (amongst other things) an appropriate degree of certainty about the regulatory framework and investment environment in order to encourage timely and efficient investment.[997]

12.2.7 ActewAGL Distribution's revised regulatory proposal

ActewAGL Distribution maintains its position in its regulatory proposal for the subsequent regulatory period (in combination with maintaining its view that the AER should continue to use the revealed costs approach to forecasting ActewAGL Distribution's opex as set out in Chapter 3):

- that the Historical EBSS apply to it with the effect that the EBSS Penalty be subtracted from its regulated revenue in the 2014–19 period;
- that the Current EBSS apply to it in the 2014–19 period but with the two modifications to the AER's approach discussed above in section 12.2.4.

In the event, the AER maintains its draft decision and makes a final decision to forecast opex on a basis other than revealed costs and to therefore not apply the Current EBSS, then ActewAGL Distribution accepts the AER's draft decision not to apply the EBSS Penalty and contends that:

- its revenue allowance should be increased for the subsequent regulatory period to ensure that ActewAGL Distribution only bears 30 per cent of the opex cost overrun from the 2009-14 regulatory control period rather than 100 per cent under the draft decision as discussed above in section 12.2.6. As discussed in Chapter 3 such an adjustment would form part of the glide path that ActewAGL Distribution contends the AER must implement; and

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[995] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015, p 29

[996] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015, p 26

[997] See, for example, AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, 16 November 2006, p. 92.

- the AER must implement a EBSS that is designed to operate in conjunction with the AER's new approach.

Application of the EBSS Penalty

The proposed EBSS carryover effect for the 2014-19 period is summarised in Table 12.2.

Table 12.2 Operating expenditure subject to the EBSS and carryover effects

($ million, 2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*
Forecast opex for EBSS purposes, $08/09	48.5	49.0	50.0	51.7	51.4
Forecast opex for EBSS purposes, $13/14	55.7	56.3	57.4	59.4	59.1
Total actual operating expenditure, $13/14	68.3	79.9	91.2	98.2	-
Excluded costs, $13/14	-11.1	-14.4	-21.1	-28.5	-
Operating expenditure subject to the EBSS, $13/14	57.2	65.5	70.1	69.7	-
Incremental gain/loss ($2013/14)	-1.5	-7.7	-3.5	2.4	
($ million, 2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Carryover effect	-10.3	-8.8	-1.1	2.4	-
Allocated to distribution	-9.0	-7.7	-1.0	2.1	-
Allocated to transmission	-1.3	-1.1	-0.1	0.3	-

Table 12.3 Operating expenditure subject to the EBSS during 2014-19, standard control services

($ million, 2013/14)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Forecast opex	76.1	75.5	73.7	75.6	76.9
Less					
Debt raising costs	1.2	1.2	1.2	1.2	1.3
Self insurance	0	0	0	0	0
Insurance	1.1	1.1	1.1	1.1	1.1
Superannuation (defined benefit)	2.4	2.4	2.4	2.4	2.4
DMIS	0.1	0.1	0.1	0.1	0.1
Costs due to new unforseen obligations			Not available yet		
Pass throughs			Not available yet		
Operating expenditure subject to the EBSS					

Changes required if the AER maintains its draft decision in respect of forecast opex and the EBSS

This section addresses the decisions that the AER must make, in addition to its current draft decision, if the AER maintains its draft decision and makes a final decision to forecast opex on a basis other than revealed costs and therefore to not apply the Current EBSS.

ActewAGL Distribution accepts the AER's draft decision that the EBSS Penalty not be applied. However, ActewAGL Distribution contends that its revenue allowance should be increased for the subsequent regulatory period such that ActewAGL Distribution only bears 30 per cent of the opex cost overrun from the 2009-14 regulatory control period rather than 100 per cent as discussed above.

In order to correct the disincentives provided by the draft decision it is imperative that the AER develop and implement an EBSS that is NEO contributing[998], compliant with clause 6.5.8(c) of the Rules and provides ActewAGL Distribution with incentives:

- that appropriately reward ActewAGL Distribution for efficient opex and improvements in efficiency;
- which are continuous;
- that do not promote inefficient trade-offs between capex and opex; and
- reflect the intended operation of the incentive schemes under the Rules.[999]

The alternative EBSS that the AER determines to apply must be one that is designed to operate in conjunction with the AER's application of benchmarking (given ActewAGL Distribution agrees with the AER that the Current EBSS is designed to work in conjunction with a revealed costs approach to forecasting opex).[1000]

As the AER's proposed approach to determining ActewAGL Distribution's opex allowance only became known to ActewAGL Distribution when it received the draft decision, in the time available it has been unable to develop an alternative EBSS and to seek the necessary expert advice that it requires to do so. Accordingly, it was not practicable for ActewAGL Distribution to propose in detail the elements of the alternative EBSS, in this revised proposal.

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[998] Relevantly the RPPs (in section 7A(3) of the NEL) require the AER to provide ActewAGL Distribution with effective incentives in order to promote economic efficiency with respect to direct control network services it provides including for it to invest efficiently in its distribution system.

[999] See Atachment C1, HoustonKemp, *Opex and the Efficiency Benefit Sharing Scheme*, January 2015, pp. 22-25

[1000] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 9: Efficiency Benefit Sharing Scheme, p. 9-8.

12.3 CESS

12.3.1 Overview

This Section responds to the AER's draft decision in respect of the CESS set out in Attachment 10 to its draft decision.

The CESS did not apply to ActewAGL Distribution in the 2009-14 regulatory control period as the AER published the first version of the Capital Expenditure Incentive Guideline for Electricity Network Service Providers (Capex Incentive Guideline), that set out the CESS, in November 2013. Nor does the CESS apply in the transitional regulatory period because the Rules preclude its application in the transitional regulatory period.[1001]

ActewAGL Distribution proposed that the AER apply the CESS to ActewAGL Distribution for the subsequent regulatory period as proposed in the AER's Stage 2 F&A Paper[1002] with two exclusions as follows:[1003]

- the exclusion of customer-initated capex (C-I Capex Exclusion); and
- the exclusion of equity raising costs (ER Costs Exclusion).

Consistent with the Stage 2 F&A Paper, in its draft decision, the AER determined to apply the CESS as set out in the Capex Incentive Guideline.[1004]

The AER does not accept ActewAGL Distribution's proposal to apply the C-I Capex Exclusion and the ER Costs Exclusion for essentially the same reasons, set out in its Explanatory Statement to the Capex Incentive Guideline,[1005] as it decided not to allow any exclusions to the CESS.

[1001] Clause 11.56.3(a)(3) of the Rules

[1002] AER 2014, *Stage 2 Framework and approach ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, January 2014, p. 28

[1003] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p.357

[1004] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 10: Capital Expenditure Sharing Scheme, p. 10-7

[1005] AER 2013, *Explanatory Statement Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013

ActewAGL Distribution accepts the AER's draft decision to apply the CESS to ActewAGL Distribution for the subsequent regulatory period and not to apply the ER Costs Exclusion but it maintains its proposal that the AER should apply the CESS subject to C-I Capex Exclusion.

ActewAGL Distribution contends that the AER's draft decision not to apply the C-I Capex Exclusion is not in accordance with law, and is unreasonable and an incorrect exercise of discretion in all the circumstances because it cannot be reconciled with the statutory object of the CESS and the AER's constituent decision on how to apply that CESS to ActewAGL Distribution for the subsequent regulatory period. That object is to reward or penalise ActewAGL Distribution for improvements or declines in capex efficiency and, in turn, provide it with an incentive to undertake efficient capex, and not inefficient capex, during the subsequent regulatory period. By contrast, the AER's draft decision results in the CESS penalising ActewAGL Distribution for something other than declines in capex efficiency and, in so doing, provides ActewAGL Distribution with incentives that are discordant with that object.

Further, in making its draft decision, the AER does not appear to have accorded weight to the matters set out in clause 6.5.8A(e) of the Rules as a fundamental element of its decision on how to apply the CESS to ActewAGL Distribution for the subsequent regulatory period, as it is required to do by that provision. Clause 6.5.8A(e) of the Rules expressly requires the AER to consider the circumstances of ActewAGL Distribution and the capital expenditure sharing scheme principles set out in clause 6.5.8A(c) of the Rules as they apply to ActewAGL Distribution in making its decision on how the CESS is to apply to ActewAGL Distribution for the subsequent regulatory period. In the draft decision, however, the AER refers to and repeats its reasons for deciding not to apply any exclusions for uncontrollable events in the CESS itself set out in its Explanatory Statement for the Capex Incentive Guideline, without giving any consideration to the applicability of that reasoning in the present circumstances. This would appear to have contributed to the making of a draft decision by the AER that cannot be reconciled with the statutory object of the CESS and the AER's constituent decision.

12.3.2 The relevant legal and regulatory framework for the CESS

The NEO and the RPPs

ActewAGL Distribution refers to and repeats the discussion of the relevance and role of the NEO and the RPPs set out in section 12.2.2 above.

Development and implementation of the CESS

Clause 6.4A of the Rules provides that the AER must, in accordance with the distribution consultation procedures, make and publish Capital Expenditure Incentive Guidelines that set out (amongst other things) any CESS developed by the AER in accordance with clause 6.5.8A of the Rules and how the AER has taken into account the capital expenditure incentive scheme principles set out in clause 6.5.8A(c) of the Rules (CESS Principles) in developing the scheme(s).

Clause 6.5.8A(a) and (b) of the Rules provides that a CESS is a scheme that provides DNSPs with an incentive to undertake efficient capex during a regulatory control period and requires the CESS to be consistent with the capital expenditure incentive objective (capex incentive objective).

Clause 6.4A(a) of the Rules provides that the capex incentive objective is to ensure that, where the value of a RAB is subject to adjustment in accordance with the Rules, then the only capex that is included in an adjustment that increases the value of that RAB is capex that reasonably reflects the capex criteria.

The capex criteria are specified in clause 6.5.7(c) of the Rules as follows:

- the efficient costs of achieving the capex objectives specified in clause 6.5.7(a) of the Rules (capex objectives);
- the costs that a prudent operator would require to achieve the capex objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives.

The capex objectives are to:

- meet or manage the expected demand for standard control services over the regulatory control period;
- comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
- to the extent that there is no applicable regulatory obligation or requirement in relation to:
    - the quality, reliability or security of supply of standard control services; or
    - the reliability or security of the distribution system through the supply of standard control services,

  to the relevant extent:
    - maintain the quality, reliability and security of supply of standard control services; and
    - maintain the reliability and security of the distribution system through the supply of standard control services; and
- maintain the safety of the distribution system through the supply of standard control services.

Clause 6.5.8A(c) of the Rules provides that, in developing a CESS, the AER must take into account the CESS Principles, being:

- DNSPs should be rewarded or penalised for improvements or declines in efficiency of capex; and
- the rewards and penalties should be commensurate with the efficiencies or inefficiencies in capex, but a reward for efficient capex need not correspond in amount to a penalty for the same amount of inefficient capex.

Clause 6.5.8A(d) of the Rules requires that, in developing a CESS, the AER must also take into account:

- the interaction of the scheme with other incentives that DNSP may have in relation to undertaking efficient opex or capex; and
- the capex objectives and, if relevant, the operating expenditure objectives.

In November 2013, the AER published version 1 of the Capex Incentive Guideline which sets out the detail of the applicable CESS.[1006]

Constituent decisions on the CESS

Clause 6.12.1(2)(i) and (9) provides that the constituent decisions by the AER on which the distribution determination for ActewAGL Distribution for the subsequent regulatory period is predicated include (amongst others):

- a decision on ActewAGL Distribution's current building block proposal in which the AER either approves or refuses to approve the ARR for ActewAGL Distribution, as set out in the building block proposal, for each regulatory year of the regulatory control period; and
- a decision on how any applicable CESS is to apply to ActewAGL Distribution.

The ARR for ActewAGL Distribution for each regulatory year of a regulatory control period must be determined using a building block approach, under which the building blocks include, amongst other things, the revenue increments or decrements (if any) for each regulatory year of the regulatory control period arising from the application of the CESS referred to in clause 6.5.8A of the Rules during the previous regulatory control period (clause 6.4.3(a)). As the CESS did not apply to ActewAGL Distribution in the 2009-14 regulatory control period or the transitional regulatory period, however, there are no revenue increments or decrements for the subsequent regulatory period arising from the application of the CESS during a previous regulatory control period.

[1006] AER 2013, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013

Clause 11.56.4(b) to (f) of the Rules provides for the application of specified provisions of current Chapter 6 of the Rules on the basis that the transitional regulatory period is to be treated as either the last regulatory year of the 2009-14 regulatory control period or the first regulatory year of the subsequent regulatory period. Clause 11.56.4(g), in turn, provides that nothing in clause 11.56.4 has the effect of actually rendering the transitional regulatory period as the first regulatory year of the subsequent regulatory period and, except for the purposes of the application of paragraphs (b) to (f) in accordance with their terms, the transitional regulatory period must be treated as a regulatory control period that is separate to the subsequent regulatory period. Clause 6.12.1(9) of current Chapter 6, which provides for the making of the constituent decision on how any applicable CESS is to apply to ActewAGL Distribution, is not referred to in paragraphs (b) to (f) of clause 11.56.4.

It follows that, in making the distribution determination for ActewAGL Distribution for the subsequent regulatory period, the AER's decision is in respect of how any applicable CESS is to apply to ActewAGL Distribution in the subsequent regulatory period.[1007]

Relevantly, in deciding whether to apply a CESS, and the nature and details of any CESS that is to apply, to ActewAGL Distribution for the subsequent regulatory period, clause 6.5.8A(e) requires the AER to:

- make that decision in a manner that contributes to the achievement of the capex incentive objective; and
- take into account the CESS Principles and the matters referred to in clause 6.5.8A(d) of the Rules, as they apply to ActewAGL Distribution, and the circumstances of ActewAGL Distribution.

12.3.3 ActewAGL Distribution's proposal

ActewAGL Distribution proposed that the AER apply the CESS to ActewAGL Distribution for the subsequent regulatory period as proposed in the AER's Stage 2 F&A Paper[1008] subject to two exclusions being:[1009]

[1007] Clause 11.56.3(a)(3) of the Rules required the distribution determination made by the AER for ActewAGL Distribution for the TRP to specify that no CESS applies to ActewAGL Distribution for the TRP

[1008] AER 2014, *Stage 2 Framework and approach ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, January 2014, p. 28

[1009] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 357

- the C-I Capex Exclusion; and
- the ER Costs Exclusion.

ActewAGL Distribution's reasons for proposing the C-I Capex Exclusion were:[1010]

- it generally does not control the incurring of customer initiated capex, which is by its very nature unilaterally requested by a customer to occur at a time dictated by the customer; and
- as customer initiated capex is often outside the control of ActewAGL Distribution (and sometimes driven by government requirements), there is acute uncertainty inherent in forecasting this type of expenditure, particularly in the outer years of a regulatory control period.

While customer initiated capex forecasts are included in ActewAGL Distribution's forecast capex for the 2014-19 period, ActewAGL Distribution reasoned that, as such expenditure is initiated by third parties, it is not possible to foresee all projects that will take place in the outer years. Accordingly, it is reasonably likely that, if customer initiated capex is included in the CESS, a CESS penalty will be applied to ActewAGL Distribution in relation to currently unforseeable future projects.[1011] This is because there will likely be a capex overspend.[1012]ActewAGL Distribution concluded that the AER should apply the C-I Capex Exclusion as it may otherwise have an incentive to underspend on capital projects elsewhere in its capex program to avoid facing a CESS penalty in the subsequent regulatory period.[1013]

[1010] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 357

[1011] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 358-359

[1012] See Table 16.2 and the associated discussion in ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 358

[1013] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 359

ActewAGL Distribution's reasons for proposing the ER Costs Exclusion were that:[1014]

- equity raising costs were not being forecast using the standard forecast methodology as used for the remaining capex program but using a benchmark methodology; and
- accordingly, consistent with the AER's view that debt raising costs should be excluded from the EBSS, equity raising costs should also be excluded from the CESS.

12.3.4 AER draft decision

Consistent with its approach proposed in the Stage 2 F&A Paper, in its Draft Decision, the AER determines to apply the CESS as set out in the Capex Incentive Guideline.[1015]

The AER does not accept ActewAGL Distribution's proposal to apply the C-I Capex Exclusion and the ER Costs Exclusion.

The AER states that its Capex Incentive Guideline does not provide for any exclusions to the CESS for DNSPs and that its reasons for deciding not to allow any exclusions are set out in the Explanatory Statement to the Capex Incentive Guideline.[1016] The AER notes that ActewAGL Distribution did not present any evidence that was new or additional to that considered by the AER in the consultation process regarding the Capex Incentive Guideline.

The AER repeats its view from the Explanatory Statement to the Capex Incentive Guideline,[1017] that it does not consider there is a convincing reason to allow exclusions to the CESS for capex resulting from uncontrollable events because, when included in the CESS, the cost of any capex increase or decrease from an uncontrollable event is shared between NSPs and consumers *'in the same way as any other capex efficiency gain or loss'*.[1018] The AER notes:[1019]

[1014] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 360

[1015] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 10: Capital Expenditure Sharing Scheme, p. 10-7

[1016] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 10: Capital Expenditure Sharing Scheme, p. 10-10; AER 2013, *Explanatory Statement Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, pp. 37-41

[1017] AER 2013, *Explanatory Statement Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, p. 38

[1018] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 10: Capital Expenditure sharing Scheme, p. 10-10

If we excluded capex resulting from uncontrollable events from the CESS, the associated capex underspend or overspend will still be shared between the service provider and consumers. However, when excluded from the CESS the relative sharing ratio between the service provider and consumers will depend on the year in which the overspend or underspend occurs, and will vary across the regulatory control period. We considered there was no reason why capex overspends or underspends resulting from uncontrollable events should be shared differently between service providers and consumers in each regulatory year, or shared differently to all other costs facing service providers.

In addition, the AER states that it considers the contingent projects and pass-through mechanisms mean a service provider could seek approval for additional material capex not included in its total forecast capex.[1020] Where the associated capex does not meet the materiality thresholds for these mechanisms, the AER does not see any reason why immaterial capex should be excluded from the CESS.

The AER acknowledges that the CESS will reward or penalise service providers for some uncontrollable events.[1021] However it concludes that, on the whole, the risk of uncontrollable events presents both upside and downside risk to service providers. Further, the AER states that, while it accepts that some events may be uncontrollable, in most cases, a service provider can strive to control the resulting costs. The AER reasons that, by contrast, allowing exclusions would increase the risk that a service provider's incentives to improve its capex efficiency would be diluted.

The AER does not accept the ER Costs Exclusion as it does not consider the potential exclusion of debt raising costs from the EBSS by the AER provides a basis for excluding equity raising costs from the CESS.[1022] This is because the reason for excluding debt raising costs from the EBSS is not applicable to the treatment of equity raising costs by the CESS.

[1019] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 10: Capital Expenditure sharing Scheme, p. 10-10

[1020] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014, Attachment 10: Capital Expenditure Sharing Scheme*, p. 10-10; see also AER 2013, *Explanatory Statement Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, p. 39

[1021] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 10: Capital Expenditure Sharing Scheme, p. 10-10; see also AER 2013, *Explanatory Statement Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, p. 38

[1022] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 10: Capital Expenditure Sharing Scheme, p. 10-11

12.3.5 ActewAGL Distribution’s response and revised proposal

ActewAGL Distribution accepts the AER's draft decision that it should be subject to the CESS for the subsequent regulatory period. In addition, due to the small amount that equity raising costs are likely to represent, ActewAGL Distribution does not pursue its proposal that the CESS should apply subject to the ER Costs Exclusion and, accordingly, accepts the AER's draft decision not to apply the ER Costs Exclusion.

ActewAGL Distribution maintains, however, that the CESS should apply subject to the C-I Capex Exclusion for the reasons set out in its regulatory proposal for the subsequent regulatory period.[1023] ActewAGL Distribution refers to and repeats its contentions in support of the application of the C-I Capex Exclusion set out in its regulatory proposal for the subsequent regulatory periodand responds to the AER's draft decision not to apply that Exclusion as follows.

ActewAGL Distribution considers that Table 12.4, which compares customer initiated capex outcome with ActewAGL Distribution’s forecast in 2008for the 2009-14 period further illustrates the uncontrollable nature in customer initiated capex incurred and uncertainty inherent in forecasting customer initiated capex, which is unrelated to whether the expenditure is being efficient or not.

Table 12.4 Customer initiated capex outcome versus forecast

($ million 2013/14)	*2009/10*	*2010/11*	*2011/12*	*2012/13*	*2013/14*	*Total*
Actual customer initiated expenditure	26.5	33.0	30.5	24.6	23.6	138.1
Forecast customer initiated expenditure	23.3	26.6	23.4	18.0	15.5	106.7
Difference	**3.2**	**6.4**	**7.1**	**6.6**	**8.1**	**31.4**

The AER's draft decision not to apply the C-I Capex Exclusion is not in accordance with law, and is unreasonable and an incorrect exercise of discretion in all the circumstances because it cannot be reconciled with the statutory object of the CESS and the AER's constituent decision on how to apply that CESS to ActewAGL Distribution for the subsequent regulatory period.

The CESS is stated by the Rules to be a scheme that provides DNSPs with an incentive to undertake efficient capex during a regulatory control period.[1024] The capex incentive objective, defined by reference to the capex criteria and with which any CESS developed by the AER must

[1023] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 357-359

[1024] Clause 6.5.8A(a) of the Rules

be consistent,[1025] is likewise concerned with the creation of incentives for a DNSP to incur capex efficiently (as the capex criteria include the efficient costs of achieving the capex objectives).[1026] Similarly, the CESS Principles, to which the AER must have regard in developing any CESS, include that DNSPs should be rewarded or penalised for improvements or declines in the efficiency of capex.[1027]

In deciding whether and how to apply the CESS to ActewAGL Distribution for the subsequent regulatory period, the AER is, in turn, required to:[1028]

- make a decision that contributes to the achievement of the capex incentive objective, which as noted above is concerned with the creation of incentives for a DNSP to incur capex efficiently; and
- take into account the CESS Principles which as noted above include that DNSPs should be rewarded or penalised for improvements or declines in the efficiency of capex.

The statutory object for the AER's constituent decision on how to apply that CESS to ActewAGL Distribution for the subsequent regulatory period is to reward or penalise ActewAGL Distribution for improvements or declines respectively in the efficiency of its capex so as to provide it with an incentive to undertake efficient capex, and not inefficient capex, during the subsequent regulatory period.

In the absence of the C-I Capex Exclusion, ActewAGL Distribution will be penalised by the CESS for undertaking any customer requested capex during the subsequent regulatory period, the need for which cannot currently be identified by ActewAGL Distribution with the same degree of certainty as for other capex drivers and, thus, is not proposed to, nor will it, be included in its forecast capex for the 2014-19 period notwithstanding that additional customer requests for capex will almost certainly occur during the period and ActewAGL Distribution will have very little (if any) control over whether to incur capex or the timing of doing so. In short, ActewAGL Distribution will, almost inevitably, be penalised under the CESS for capex it incurs efficiently (and for which it will also be uncompensated through allowed revenues). As ActewAGL Distribution has little control over whether to incur customer initiated capex or its timing, it follows that the application of the CESS in the absence of the C-I Capex Exclusion will create an

[1025] Clause 6.5.8A(b) of the Rules

[1026] Clauses 6.4A(a) and 6.5.7(c) of the Rules

[1027] Clauses 6.4A(b)(1) and 6.5.8A(c) of the Rules

[1028] Clause 6.5.8A(e) of the Rules

incentive for ActewAGL Distribution not to undertake other efficient capex during the subsequent regulatory period.

Such a result cannot be reconciled with the statutory object for the AER's constituent decision on how to apply the CESS to ActewAGL Distribution in that it results in the CESS penalising ActewAGL Distribution for something other than declines in capex efficiency and, in so doing, provides ActewAGL Distribution with incentives that are discordant with the capex incentive objective and the broader statutory object for the CESS and that constituent decision.

As the CESS and the AER's constituent decision on how it is to apply to ActewAGL Distribution in the subsequent regulatory period are intended to promote the efficiency objectives of the NEO, it follows that the AER's decision not to apply the C-I Capex Exclusion does not contribute to the achievement of the NEO and, accordingly, is not compliant with the AER's obligation under section 16(1)(d) of the NEL to make the NEO preferable decision.

Further, in making its draft decision, the AER does not appear to have accorded weight to the matters set out in clause 6.5.8A(e) of the Rules as a fundamental element of its decision on how to apply the CESS to ActewAGL Distribution for the subsequent regulatory period, as it is required to do by that provision.

In the draft decision, the AER refers to and repeats its reasons for deciding not to apply any exclusions for uncontrollable events in the CESS itself set out in its Explanatory Statement for the Capex Incentive Guideline. It does not give any consideration to the applicability of that reasoning to ActewAGL Distribution for the subsequent regulatory period, to its particular proposal in respect of the C-I Capex Exclusion Proposal, to ActewAGL Distribution's circumstances (including for example its approach of reflecting only known requests for customer initiated capex in its proposed forecast of customer initiated capex for the 2014-19 period) or to the particular matters raised by ActewAGL Distribution in relation to the proposed C-I Capex Exclusion in its regulatory proposal for the SRP.

Even in the absence of clause 6.5.8A(e) of the Rules, this would constitute an improper exercise of the AER's power. Clause 6.5.8A(e) of the Rules, however, expressly requires the AER to consider the circumstances of ActewAGL Distribution and the CESS Principles as they apply to ActewAGL Distribution in making its decision on how the CESS is to apply to ActewAGL Distribution for the subsequent regulatory period. In making its draft decision on the proposed C-I Capex Exclusion, the AER has manifestly failed to do so. This would appear to have contributed to the making of a draft decision by the AER that cannot be reconciled with the statutory object of the CESS and the AER's constituent decision.

For this reason also, the AER's draft decision on the proposed C-I Capex Exclusion is not in accordance with law, and is an incorrect exercise of discretion and unreasonable in all the circumstances.

In respect of the specific contentions advanced by the AER (by reference to its Explanatory Statement for the Capex Incentive Guideline) for its draft decision not to apply the C-I Capex Exclusion, ActewAGL Distribution responds as follows:

- In concluding that the C-I Capex Exclusion should not apply because a sharing ratio of 30:70 is appropriate for any capex underspends and overspends regardless of whether those underspends and overspends represent efficiency improvements or declines respectively, the AER has improperly exercised its power in that it has taken into account an irrelevant consideration and exercised its power for a purpose other than that for which it was conferred. As discussed above, the Rules disclose that the CESS and the constituent decision on how it is to apply are to reward or penalise ActewAGL Distribution for improvements or declines respectively in the efficiency of its capex so as to provide it with an incentive to undertake efficient capex, and not inefficient capex, during the subsequent regulatory period. The AER's policy view that capex underspends and overspends that do not represent improvements or declines in efficiency should be shared between DNSPs and consumers in the same way as improvements and declines in efficiency (i.e. 30: 70) is irrelevant. The Rules do not permit the AER to decline to apply the C-I Capex Exclusion to achieve its stated purpose of ensuring a 30:70 sharing of capex underspends and overspends that are not referable to efficiency improvements or declines.
- With respect to the AER's conclusion that the C-I Capex Exclusion should not apply because the contingent projects and pass-through mechanisms provide a service provider with an avenue for obtaining approval to additional material capex not included in its forecast capex, ActewAGL Distribution contends that
    - this is incorrect because:
        - the only relevant mechanism could be the 'regulatory change' pass through event and it is rare for customer initiated capex to be incurred in circumstances where this event would likely apply;
        - the AER's draft decision (discussed in Chapter 12 of this revised regulatory proposal) was to reject ActewAGL Distribution's proposed 'general pass through event' in Attachment 15 to the draft decision, which event may otherwise have provided ActewAGL Distribution with a mechanism to recover additional material customer initiated capex; and
    - in any event, the existence of the contingent projects and pass-through mechanisms does not assist to remedy the issues with the AER's draft decision not to apply the C-I Capex Exclusion outlined above and thus render that decision legally permissible, correct or reasonable.

- With respect to the AER's conclusion that there is no reason why any capex that is not so approved as a contingent project or pass-through because it is immaterial should be excluded ex-ante from the CESS, ActewAGL Distribution responds that if, as is the case for customer iniated capex, it is known ex ante that the incurring of the immaterial capex would not represent a decline in capex efficiency, this is just such a reason and indeed, for the reasons discussed above, its inclusion in the CESS would be inconsistent with the statutory object of that CESS and would not be authorised by the Rules.
- The AER's conclusion that, while the CESS will reward or penalise service providers for some uncontrollable costs, the resultant risk to service providers is symmetric is not applicable to ActewAGL Distribution's customer initiated capex and thus provides no support for the AER's draft decision not to apply the C-I Capex Exclusion. To the contrary, there will be a systematic bias in the application of the CESS to ActewAGL Distribution in the absence of the C-I Capex Exclusion because ActewAGL Distribution reflects only known requests for customer initiated capex in its proposed (and revised proposed) forecast of customer initiated capex for the 2014-19 period notwithstanding that additional customer requests for capex will almost certainly occur during the period. That is, the risk to ActewAGL Distribution where the CESS applies in the absence of the C-I Capex Exclusion will not be symmetric.
- In respect of the AER's conclusion that a service provider can strive to control the costs resulting from uncontrollable events and the application of the CESS to uncontrollable events would provide a service provider with incentives to incur capex in response to an uncontrollable event efficiently, ActewAGL Distribution observes that:
    - any customer request for customer initiated capex during the subsequent regulatory period that is not known at this time, and thus not reflected in ActewAGL Distribution's proposed or revised proposed forecast capex for the 2014-19 period, will necessarily result in capex being incurred that, all else being equal, exceeds ActewAGL Distribution's forecast capex allowance for 2014-19 but does not represent a decline in capex efficiency;
    - for the reasons already explained, it follows that the application of the CESS to customer initiated capex will almost inevitably penalise ActewAGL Distribution for capex that does not represent an efficiency decline and create an incentive for it to not undertake efficient capex during the subsequent regulatory period, contrary to the scheme and object of the Rules; and
    - any ability ActewAGL Distribution has to control the quantum of customer initiated capex it incurs as a result of such requests will be at the margin, with the consequence that the benefits of creating an incentive for efficiency in respect of the amount of customer initiated capex incurred by applying the CESS

to customer initiated capex are outweighed by the other effects this would have on incentives for efficiency already noted.

Thus, the creation of an incentive for efficiency in respect of the amount of customer initiated capex incurred by ActewAGL Distribution as a result of any customer request for customer initiated capex during the subsequent regulatory period cannot properly be said to justify a decision not to apply the C-I Capex Exclusion.

12.4 STPIS

12.4.1 Overview

This Section 12.4responds to the AER's draft decision in respect of the STPIS set out in Attachment 11 to its Draft Decision.

ActewAGL Distribution briefly outlines its STPIS proposal (in section 12.4.3) and the AER's draft decision on STPIS (in section 12.4.4) and then details ActewAGL Distribution's response to that draft decision (in section 12.4.5) and sets out its revised proposal (in section 12.4.6).

A STPIS did not apply to ActewAGL Distribution in the 2009-14 regulatory control period and does not apply to it in the TRP.

In its regulatory proposal for the subsequent regulatory period, however, ActewAGL Distribution proposed, consistent with the AER's approach proposed in the Stage 2 F&A Paper, that the s-factor component of the current Service Target Performance Incentive Scheme for electricity DNSPs[1029] (the national STPIS) be applied to ActewAGL Distribution in the subsequent regulatory period. It also proposed two modifications to the national STPIS being changes to the:[1030]

- performance targets for the reliability of supply component;[1031] and
- value of customer reliability (VCR) used to set incentive rates for the reliability of supply component.[1032]

[1029] AER 2009, *Electricity distribution network service providers—service target performance incentive scheme*, 1 November 2009

[1030] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 365. In its Stage 2 F&A Paper, the AER noted the ability of DNSPs to propose to vary the application of the national STPIS in their regulatory proposal, see AER 2014, *Stage 2 Framework and Approach ActewAGL*, January 2014, p. 20

[1031] Clauses 3.2.1(a) and 5.3.1(b) of the national STPIS

ActewAGL Distribution's proposed performance targets for the reliability of supply component were based on the minimum standards in the ACT Supply Standards Code.[1033] This was to take into account that there had been a change in the Rule provisions governing the forecast opex and capex allowed in respect of quality, reliability and security, as a consequence of the AEMC's NSP Expenditure Objectives Rule change, with the result that there would otherwise be an inconsistency between the historical reliability levels used to set the performance targets for the reliability of supply component to apply in the subsequent regulatory period and the reliability levels reflected in ActewAGL Distribution's forecast opex and capex for the period.[1034]

In order to reflect the willingness of the ACT based customer or end user to pay for improved performance in the delivery of services, ActewAGL Distribution proposed a VCR estimate and corresponding STPIS incentive rates based on evidence from choice modelling studies conducted in the ACT by NERA and the ANU.[1035]

The AER's draft decision is to apply the s-factor component of the national STPIS to ActewAGL Distribution without the modifications proposed by ActewAGL Distribution. More specifically:

- the AER does not accept ActewAGL Distribution's proposed performance targets for the reliability of supply component because those targets are based on minimum standards which the AER considers that ActewAGL Distribution is currently comfortably outperforming. The AER instead sets ActewAGL Distribution's performance targets based on its average performance over the past five regulatory years in accordance with the national STPIS[1036]; and
- the AER determines that the AEMO VCR review published in September 2014 (AEMO VCR Review) represents the best available information for determining the applicable VCR. The

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[1032] In accordance with clause 3.2.2(d) of the national STPIS

[1033] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 361 and 365-367

[1034] AEMC 2013, *Rule Determination National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013*, 19 September 2013

[1035] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 372-376

[1036] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period, Attachment 11: Service target performance incentive scheme*, November 2014, p. 11-8

AER therefore calculates ActewAGL Distribution's incentive rates for the reliability of supply component based on the AEMO VCR Review.[1037]

In ActewAGL Distribution's response to the AER's draft decision, it contends that the AER's draft decision on the application of the national STPIS to ActewAGL Distribution is not in accordance with law, involves a material error, or material errors, of fact, is an incorrect exercise of discretion and is unreasonable in all the circumstances for the following reasons:

- In determining to apply the national STPIS to ActewAGL Distribution without any modification in respect of performance parameters, the AER has failed to take into account:
    - the inter-relationship between its decision to apply the national STPIS to ActewAGL Distribution for the subsequent regulatory period, including in particular as to the performance targets to apply, and its decision on forecast expenditure allowances for that period, notwithstanding that the AER has an obligation to take that inter-relationship into account in the making of its Draft Decision under clauses 6.5.6(e)(8) and 6.5.7(e)(8);
    - that there has been a change in the Rules governing forecast expenditure allowances as a result of the AEMC NSP Expenditure Objectives Rule change that means the AER's draft decisions in respect of forecast opex and capex reflect only the expenditure required to achieve the reliability levels specified by ActewAGL Distribution's regulatory obligations and requirements in respect of quality and reliability; and
    - that, thus, those expenditure allowances are inconsistent with the application of performance targets for the STPIS that are based on significantly higher historical reliability levels as proposed by the AER.
- As ActewAGL Distribution's expenditure allowances for the subsequent regulatory period will fund it only to meet its regulatory obligations and requirements in respect of quality and reliability and not to maintain its materially higher historical performance, the draft decision will operate to impose an expected loss on ActewAGL Distribution, in the form of a STPIS penalty, which is inconsistent with clause 7A(2) of the NEL, in that a reasonable opportunity will not be provided to ActewAGL Distribution to recover at least its efficient costs.

[1037] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014, Attachment 11: Service target performance incentive scheme*, November 2014, p. 11-9

- The large difference in AEMO's VCR estimate for the NSW NEM region (of around $38/kWh, excluding direct connects) and the estimate derived by ActewAGL Distribution for the ACT (of around $67/kWh) establishes that the value placed on reliability by customers in the ACT is different to the value placed on reliability by customers in New South Wales. In placing primary reliance on the VCR estimated by AEMO, the AER has failed to discharge its obligations under the Rules, in particular to take into account the circumstances of ActewAGL Distribution and the customers or end users that ActewAGL Distribution supplies.

In this revised regulatory proposal, ActewAGL Distribution continues to propose that the s-factor component of the national STPIS be applied to ActewAGL Distribution with modifications to the:

- performance targets for the reliability of supply component; and
- VCR used to set incentive rates for the reliability of supply component.

In response to the AER's contention in respect of performance targets that ActewAGL Distribution's performance in the subsequent regulatory period will be more a function of its historical expenditure allowances than its expenditure allowances for that period, ActewAGL Distribution has amended its proposed performance targets in this revised regulatory proposal to account for the effects of historical expenditure. It maintains, however, its original proposal in respect of the VCR used to set incentive rates.

ActewAGL Distribution also proposes that, in light of the draft decision on forecast opex and the need for ActewAGL Distribution to revise its originally proposed performance targets (on which its original proposal for revenue at risk was dependent) in response to the AER's draft decision on the STPIS, a further modification be made to ensure the level of revenue at risk is symmetric, with the cap on annual rewards corresponding to feasible levels of uSAIFI and uSAIDI. Specifically, ActewAGL Distribution proposes that the level of revenue at risk under STPIS should now be set at ±2.5 per cent, rather than ±5 per cent as originally proposed.

12.4.2 The relevant legal and regulatory framework for the STPIS

The NEO and the RPPs

ActewAGL Distribution refers to and repeats the discussion of the relevance and role of the NEO and the RPPs set out above.

ActewAGL Distribution further observes that, in addition to the RPPs there discussed, the RPPs relevantly include:

> *(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in-*
>
> *(a) providing direct control network services; and*

> (b) *complying with a regulatory obligation or requirement or making a regulatory payment.*

The Tribunal has had cause to consider this RPP and has stated as follows with respect to its intent and operation:[1038]

> *It might be asked why the NEL principles require that the regulated NSP be provided with the opportunity to recover at least its efficient costs. Why 'at least'? The issue of opportunity is critical to the answer. The regulatory framework does not guarantee recovery of costs, efficient or otherwise. Many events and circumstances, all characterized by various uncertainties, intervene between the ex ante regulatory setting of prices and the ex post assessment of whether costs were recovered. But if, as it were, the dice are loaded against the NSP at the outset by the regulator not providing the opportunity for it to recover its efficient costs (eg, by making insufficient provision for its operating costs or its cost of capital), then the NSP will not have the incentives to achieve the efficiency objectives, the achievement of which is the purpose of the regulatory regime.*
>
> *Thus, given that the regulatory setting of prices is determined prior to ascertaining the actual operating environment that will prevail during the regulatory control period, the regulatory framework may be said to err on the side of allowing at least the recovery of efficient costs. This is in the context of no adjustment generally being made after the event for changed circumstances.*

Development and implementation of the STPIS

Clause 6.6.2(a) of the Rules requires the AER to develop and publish a STPIS to provide incentives for DNSPs to maintain and improve performance.

In developing and implementing a STPIS, clause 6.6.2(b)(3) of the Rules requires the AER to:

- consult with authorities responsibilities for the administration of relevant jurisdictional electricity legislation;
- ensure that service standards and service targets do not put at risk DNSPs' ability to comply with relevant service standards and service targets as specified in jurisdictional electricity legislation; and
- take into account:

[1038] *Application by Energy Australia and Others* [2009] ACompT 8 (with Corrigendum) at [81]-[82]

- the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs;
- any regulatory obligation or requirement to which the DNSP is subject;
- the past performance of the distribution network;
- any other incentives available to the DNSP under the Rules or a relevant distribution determination;
- the need to ensure that the incentives are sufficient to offset any financial incentives the DNSP may have to reduce costs at the expense of service levels;
- the willingness of the customer or end user to pay for improved performance in the delivery of services; and
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

In November 2009, the AER published the national STPIS for DNSPs. The STPIS contains two mechanisms, being:

- the service standards factor (s-factor) adjustment to the ARR for standard control services to reward or penalise DNSPs for improved or diminished service respectively compared to predetermined targets relating to reliability and quality of supply, and customer service; and
- a guaranteed service level (GSL) component composed of direct payments to customers experiencing service below a predetermined level.

Clause 2.1(d) of the national STPIS relevantly requires the AER to determine, in accordance with the Rules:[1039]

- each applicable component and parameter to apply to a DNSP including the method of network segmentation for the reliability of supply component;
- the revenue at risk to apply to each applicable component and parameter;
- the incentive rate to apply to each applicable parameter including the VCR to be applied; and

[1039] AER 2009, *Electricity distribution network service providers Service target performance incentive scheme*, November 2009, pp. 5-6

- the performance target to apply to each applicable parameter in each regulatory year of the regulatory control period.

Clause 2.2(a) of the national STPIS contemplates that a DNSP may make a proposal to vary the application of the STPIS in its regulatory proposal.[1040] If a DNSP does so, then clause 1.8 of the national STPIS provides that that proposal must:[1041]

- demonstrate how the proposed amendment is consistent with the objectives in clause 1.5 (clause 1.8(e) of the national STPIS); and
- if it adds or varies a parameter:
    - provide information and quantitative data on its performance history covering at least the most recent three to five regulatory years, as measured by its proposed parameter; or
    - where this performance history information is not available, provide an appropriate benchmark or methodology to set performance targets, and incentive rates for the proposed parameter (clause 1.8(f) of the national STPIS).

Constituent decisions on the STPIS

Clause 6.12.1(2)(i) and (9) provides that the constituent decisions by the AER on which the distribution determination for ActewAGL Distribution for the subsequent regulatory period is predicated include (amongst others):

- a decision on ActewAGL Distribution's current building block proposal in which the AER either approves or refuses to approve the ARR for ActewAGL Distribution, as set out in the building block proposal, for each regulatory year of the regulatory control period; and
- a decision on how any applicable STPIS is to apply to ActewAGL Distribution.

The ARR for ActewAGL Distribution for each regulatory year of a regulatory control period must be determined using a building block approach, under which the building blocks include, amongst other things, the revenue increments or decrements (if any) for each regulatory year of the regulatory control period arising from the application of the STPIS referred to in clause 6.6.2 of the Rules (clause 6.4.3(a) and (b)). As the STPIS did not apply to ActewAGL Distribution in the 2009-14 regulatory control period or the TRP, however, there are no revenue increments or

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[1040] AER 2009, *Electricity distribution network service providers Service target performance incentive scheme*, November 2009, p. 6

[1041] AER 2009, *Electricity distribution network service providers Service target performance incentive scheme*, November 2009, p. 3

decrements for the subsequent regulatory period arising from the application of the STPIS during a previous regulatory control period.

Clause 11.56.4(b) to (f) of the Rules provides for the application of specified provisions of current Chapter 6 of the Rules on the basis that the TRP is to be treated as either the last regulatory year of the 2009-14 regulatory control period or the first regulatory year of the subsequent regulatory period. Clause 11.56.4(g), in turn, provides that nothing in clause 11.56.4 has the effect of actually rendering the TRP as the first regulatory year of the subsequent regulatory period and, except for the purposes of the application of paragraphs (b) to (f) in accordance with their terms, the TRP must be treated as a regulatory control period that is separate to the subsequent regulatory period. Clause 6.12.1(9) of current Chapter 6, which provides for the making of the constituent decision on how any applicable STPIS is to apply to ActewAGL Distribution, is not referred to in paragraphs (b) to (f) of clause 11.56.4.

It follows that, in making the distribution determination for ActewAGL Distribution for the subsequent regulatory period, the AER's decision is in respect of how any applicable STPIS is to apply to ActewAGL Distribution in the subsequent regulatory period.[1042]

Clause 6.8.1(b)(2)(iii) of the Rules relevantly provides that a framework and approach paper that applies in respect of a distribution determination must set out the AER's proposed approach, for the purposes of that determination, to the application to ActewAGL Distribution of any STPIS. Clause 11.56.4(l) of the Rules provides that the AER must make the framework and approach paper(s) that apply in respect of a distribution determination for ActewAGL Distribution for the subsequent regulatory period in two stages, with the matters referred to here to be addressed in the 'Stage 2 F&A Paper'.

In the Stage 2 F&A Paper, the AER indicated its intention to apply the s-factor component of the national STPIS to ActewAGL Distribution in the subsequent regulatory period.[1043] This was

[1042] Clause 11.56.3(a)(4) of the Rules required the distribution determination made by the AER for ActewAGL Distribution for the TRP to specify the STPIS that applied to ActewAGL Distribution under its distribution determination for the 2009-14 regulatory control period applies to ActewAGL Distribution in the TRP subject to such modifications as are set out in the framework and approach paper that is published in respect of the SRP for ActewAGL Distribution. Clause 11.56.3(h)(3) of the Rules provides that a framework and approach paper that is published in respect of the SRP for ActewAGL Distribution may specify in relation to the distribution determination for the TRP, the modifications to be made to an incentive scheme referred to in paragraph (a)(4). The national STPIS did not apply to ActewAGL Distribution in the 2009-14 regulatory control period and in its Stage 2 F&A Paper the AER proposed not to apply the STPIS in the TRP.

[1043] AER 2014, *Stage 2 Framework and approach ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, January 2014, p. 14

despite the fact that it was aware (as at January 2014) of policy reviews by the AEMC[1044] and AEMO[1045] indicating the need to reform the national STPIS.[1046] The AER concludes:[1047]

> *there is inadequate time to review our national STPIS to incorporate the findings of these reviews before finalising our determinations for ActewAGL.*

In applying the s-factor component of the national STPIS to ActewAGL Distribution for the subsequent regulatory period, the AER proposed to:[1048]

- set revenue at risk for ActewAGL Distribution at ±5 per cent;
- segment the network according to the urban and short rural feeder categories;
- set applicable parameters to be:
    - for the reliability of supply component: the SAIDI and the SAIFI; and
    - for the customer service component: telephone answering;
- set performance targets based on ActewAGL Distribution's average performance over the past five regulatory years;
- apply the methodology indicated in the national STPIS for excluding specific events from the calculation of annual performance and performance targets; and
- apply the methodology and VCR values as indicated in our national STPIS to the calculation of incentive rates.

Inter-relationship between STPIS and forecast opex and capex

The Rules expressly recognise the inter-relationship between the AER's constituent decisions on ActewAGL Distribution's forecast opex and capex for the subsequent regulatory period, and its constituent decision on how to apply the STPIS for the period.

[1044] AEMC, *Final Report: Review of the national framework for distribution reliability*, 27 September 2013

[1045] AEMO, *Directions paper: Value of customer reliability*, 31 May 2013

[1046] AER 2014, *Stage 2 Framework and approach ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, January 2014, pp. 14-15

[1047] AER 2014, *Stage 2 Framework and approach ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, January 2014, p. 15

[1048] AER 2014, *Stage 2 Framework and approach ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, January 2014, p. 14

Clause 6.5.6(e)(8) of the Rules provides that, in deciding whether or not it is satisfied that ActewAGL Distribution's total forecast opex reasonably reflects the opex criteria, the AER must have regard to (amongst other things) whether the opex forecast is consistent with any STPIS that applies to ActewAGL Distribution under clause 6.6.2 of the Rules. Similarly, clause 6.5.7(e)(8) of the Rules provides that, in deciding whether or not it is satisfied that ActewAGL Distribution's total forecast capex reasonably reflects the capex criteria, the AER must have regard to (amongst other things) whether the capex forecast is consistent with any STPIS that applies to ActewAGL Distribution under clause 6.6.2 of the Rules.

The opex and capex criteria set out in clauses 6.5.6(c) and 6.5.7(c) respectively require, in essence, that ActewAGL Distribution's total forecast opex and capex respectively reasonably reflect the efficient and prudent costs of achieving the opex and capex objectives respectively. The opex and capex objectives are specified in clauses 6.5.6(a) and 6.5.7(a) respectively and, in respect of quality and reliability, are to:

> *(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
>
> *(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:*
>
> *(i) the quality, reliability or security of supply of standard control services; or*
>
> *(ii) the reliability or security of the distribution system through the supply of standard control services,*
>
> *to the relevant extent:*
>
> *(iii) maintain the quality, reliability and security of supply of standard control services; and*
>
> *(iv) maintain the reliability and security of the distribution system through the supply of standard control services[.]*

However, prior to the making of the AEMC's NSP Expenditure Objectives Rule change,[1049] which took effect on 26 September 2013, the relevant opex and capex objectives read as follows:

> *(3) maintain the quality, reliability and security of supply of* standard control services*; and*
>
> *(4) maintain the reliability, safety and security of the* distribution system *through the supply of* standard control services.

[1049] AEMC 2013, *Rule Determination National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013*, 19 September 2013

As a result of the Rule change, there has been a change to the opex and capex criteria specified by the Rules. Whereas previously these criteria required total forecast opex and capex respectively to reasonably reflect the efficient and prudent costs of maintaining the quality and reliability of supply, following the Rule change the criteria operate to require that total forecast opex and capex reasonably reflect the efficient and prudent costs required to achieve compliance with applicable regulatory obligations or requirements in respect of quality and reliability and, only to the extent that there are no such regulatory obligations or requirements, to the relevant extent maintain the quality and reliability of supply.

The stated purpose of the Rule change was to:[1050]

> *clarify that operating and capital expenditure allowances for NSPs should be no more than the level considered necessary to comply with a relevant regulatory obligation or requirement, where these have been set by the body allocated that role. Expenditure by NSPs to achieve standards above these levels should be unnecessary, as they are only required to deliver to the standards set.*

In making its determination, the AEMC stated that complying with standards in regulatory obligations or requirements is the appropriate objective for the reliability, security and quality measures set out in clauses 6.5.6 and 6.5.7 of the Rules.[1051] The AEMC further stated that the Rule change would result in:[1052]

- the expenditure an NSP includes in its regulatory proposal no longer being based on maintaining the NSP's existing levels of reliability, security or quality, even where an NSP is performing above the required standards for these measures, or where required standards for these measures are lowered; and
- consistency between the standard that the NSP is required to provide under jurisdictional requirements and the level of expenditure that the AER is required to approve through the regulatory determination process.

[1050] AEMC 2013, *Rule Determination National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013*, 19 September 2013, p. 30

[1051] AEMC, *Rule Determination National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013*, 19 September 2013, p. 10

[1052] AEMC, *Rule Determination National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013*, 19 September 2013, p. ii

Significantly, the AEMC noted that:[1053]

> *the AER might need to amend the STPIS for DNSPs and TNSPs in light of the rule as made. It might not be able to do this in time for the first NSPs that the rule as made would apply to. However, AER has some flexibility under these schemes. For example, it can choose which parameters apply and the revenue at risk under the schemes. In addition it can choose not to apply the schemes.*

12.4.3 ActewAGL Distribution's proposal

In its regulatory proposal for the subsequent regulatory period, ActewAGL Distribution broadly agreed to the AER's proposed application of the national STPIS as set out in its Stage 2 F&A Paper but proposed two modifications, being modifications to the:[1054]

- performance targets for the reliability of supply component;[1055] and
- the VCR used to set incentive rates for the reliability of supply component.[1056]

In relation to ActewAGL Distribution's proposed performance targets, ActewAGL Distribution stated that the default targets under the national STPIS would be unsuitable for it.[1057] This is because, being based on ActewAGL Distribution's historical reliability levels, they would be inconsistent with the reliability levels that, as a consequence of the AEMC's NSP Expenditure Objectives Rule change, would underpin ActewAGL Distribution's proposal for forecast opex and capex, these being the reliability levels required by ActewAGL Distribution's relevant regulatory obligations and requirements consistent with the opex and capex objectives set out in clauses 6.5.6(a) and 6.5.7(a) respectively of the Rules rather than those historically achieved by ActewAGL Distribution. ActewAGL Distribution therefore proposed that reliability performance targets for the STPIS in the 2015–19 period be modified to align with its regulatory obligations

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[1053] AEMC, *Rule Determination National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013*, 19 September 2013, p. 33

[1054] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 365

[1055] Clauses 3.2.1(a) and 5.3.1(b) of the national STPIS

[1056] In accordance with clause 3.2.2(d) of the national STPIS

[1057] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 365-367

and requirements with respect to quality and reliability, that is to be consistent with the minimum standards in the ACT Supply Standards Code.

In relation to incentive rates, ActewAGL Distribution proposed a VCR estimate and corresponding STPIS incentive rates based on evidence from choice modelling studies conducted in the ACT by NERA and the ANU.[1058]

12.4.4 AER draft decision

Consistent with the Stage 2 F&A Paper, the AER's draft decision is to apply the s-factor component of the national STPIS to ActewAGL Distribution for the subsequent regulatory period.[1059] The AER makes that decision as it considers it now has sufficient historical data (collected over the 2009–14 regulatory control period) with which to set service performance targets.

The draft decision maintains the AER's proposed approach, which approach ActewAGL Distribution had accepted in its regulatory proposal for the subsequent regulatory period, to set the revenue at risk within the range of ±5 per cent.[1060] The draft decision also maintains the AER's proposed approach, which approach ActewAGL Distribution had accepted, to use the 2.5 beta method to derive the major event day (MED) threshold.

The draft decision maintains the AER's proposed approach, in respect of which ActewAGL Distribution had proposed amendments, in relation to performance targets for the reliability of supply component.

The draft decision notes ActewAGL Distribution's proposal that its targets are consistent with the AEMC's NSP Expenditure Objectives Rule change which requires forecast opex and capex allowances to reflect the expenditure required to comply with regulatory obligations and requirements in respect of quality and reliability, rather than those allowances being set, as they were in the 2009-14 regulatory control period, by reference to the expenditure required to

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[1058] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 372-376

[1059] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period, Attachment 11: Service target performance incentive scheme*, November 2014, p. 11-7

[1060] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period, Attachment 11: Service target performance incentive scheme*, November 2014, p. 11-8

maintain quality and reliability.[1061] The AER however considers this approach is incorrect because:

- under the Rules, the STPIS must provide incentives to maintain and improve performance, and not merely meet regulatory obligations;
- ActewAGL Distribution's past expenditure allowances should have a significant effect on future performance or, put another way, its opex and capex allowances for the subsequent regulatory period are not the most important determinant of its ability to meet performance targets over the subsequent regulatory period;
- a fundamental principle underlying the STPIS is that it incentivises the DNSPs to achieve an efficient level of supply reliability in accordance with customer's VCR; and
- as ActewAGL Distribution outperforms the relevant jurisdicitional minimum standards, its proposed targets would provide it with an opportunity to make windfall gains with no corresponding benefits to consumers.

The AER, therefore, does not accept ActewAGL Distribution's proposed performance targets for the reliability of supply component as they were based on the minimum standards in the Supply Standards Code.[1062] As the AER considers that ActewAGL Distribution is currently comfortably outperforming the minimum SAIDI and SAIFI levels set out in its jurisdictional regulatory obligations, the AER instead set ActewAGL Distribution's performance targets based on the average performance over the past five regulatory years in accordance with the national STPIS.[1063]

The AER determines to apply the telephone answering parameter to ActewAGL Distribution. However, due to the data problem in the period 1 July 2008 to 30 November 2009, the AER sets the telephone answering target based on the average performance over the past four years, that is at 79 per cent.[1064]

[1061] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period, Attachment 11: Service target performance incentive scheme*, November 2014, pp. 11-14 to 11-16

[1062] ActewAGL Distribution summarises this Code in its proposal, see: ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 61

[1063] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period, Attachment 11: Service target performance incentive scheme*, November 2014, p. 11-8

[1064] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period, Attachment 11: Service target performance incentive scheme*, November 2014, p. 11-8

Instead of applying ActewAGL Distribution's proposed VCR, or the VCR prescribed in clause 3.2.2 of the national STPIS, the AER determines that the most recent VCR should be applied.[1065] The AER considers that the AEMO VCR Review represents the best available information for this purpose because the review process was comprehensive and included a survey of ACT consumers. The AER therefore calculates ActewAGL Distribution's incentive rates for the reliability of supply component based on that AEMO VCR Review for NSW/ACT.

The Draft Decision maintains the AER's proposed approach, which approach ActewAGL Distribution had accepted, that the incentive rate for the telephone answering parameter will be -0.04 per cent per unit of the telephone answering parameter (consistent with clause 5.3.2 of the national STPIS).[1066]

The AER notes that its Draft Decision does not provide ActewAGL Distribution with capex or opex allowances to improve its supply reliability for the subsequent regulatory period because, if it were to improve its reliability, it must fund those improvements itself.[1067]

12.4.5 ActewAGL Distribution's response

Overview

ActewAGL Distribution contends that the AER's draft decision on the application of the national STPIS to ActewAGL Distribution is not in accordance with law, involves a material error, or material errors, of fact, is an incorrect exercise of discretion and is unreasonable in all the circumstances for the following reasons:

- In determining to apply the national STPIS to ActewAGL Distribution without any modification in respect of performance targets, the AER has failed to take into account:
    - the inter-relationship between its decision to apply the national STPIS to ActewAGL Distribution for the subsequent regulatory period, including in particular as to the performance targets to apply, and its decision on forecast expenditure allowances for that period, notwithstanding that the AER has an

[1065] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period, Attachment 11: Service target performance incentive scheme*, November 2014, p. 11-9

[1066] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period, Attachment 11: Service target performance incentive scheme*, November 2014, p. 11-9

[1067] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period, Attachment 11: Service target performance incentive scheme*, November 2014, p. 11-12

obligation to take that inter-relationship into account in the making of its Draft Decision under clauses 6.5.6(e)(8) and 6.5.7(e)(8);

    - that there has been a change in the Rules governing forecast expenditure allowances as a result of the AEMC NSP Expenditure Objectives Rule change that means the AER's draft decisions in respect of forecast opex and capex reflect only the expenditure required to achieve the reliability levels specified by ActewAGL Distribution's regulatory obligations and requirements in respect of quality and reliability; and
    - that, thus, those expenditure allowances are inconsistent with the application of performance targets for the STPIS that are based on significantly higher historical reliability levels as proposed by the AER.

- As ActewAGL Distribution's expenditure allowances for the subsequent regulatory period will fund it only to meet its regulatory obligations and requirements in respect of quality and reliability and not to maintain its materially higher historical performance, the draft decision will operate to impose an expected loss on ActewAGL Distribution, in the form of a STPIS penalty, which is inconsistent with clause 7A(2) of the NEL, in that a reasonable opportunity will not be provided to ActewAGL Distribution to recover at least its efficient costs.
- The AER's draft decision to set STPIS incentive rates based on the VCR estimated by AEMO, rather than on VCR evidence from the ACT as proposed by ActewAGL Distribution is inconsistent with clause 6.6.2(b)(3)(vi) of the Rules, which requires the AER to take into account the willingness of the customer or end user to pay for improved performance in the delivery of services.

ActewAGL Distribution's response to the AER's draft decision in respect of performance targets, incentive rates and its comments on the implications of the draft decision for the appropriate revenue at risk under the STPIS are set out below.

Performance targets

The AER does not accept ActewAGL Distribution's proposed performance targets for the reliability of supply component as they are based on the minimum standards in the Supply Standards Code. The AER's primary reason for doing so appears to be its reliance on the requirements of clause 6.6.2 of the Rules, that a STPIS must provide incentives to maintain and improve performance not to merely meet regulatory obligations.[1068]

In so concluding the AER fails to take into account:

- the inter-relationship between its decision to apply the national STPIS to ActewAGL Distribution for the subsequent regulatory period, including in particular as to the performance targets to apply, and its decision on forecast expenditure allowances for that period, notwithstanding that the AER has an obligation to take that inter-relationship into account in the making of its Draft Decision under clauses 6.5.6(e)(8) and 6.5.7(e)(8);
- that there has been a change in the Rules governing forecast expenditure allowances as a result of the AEMC NSP Expenditure Objectives Rule change that means the AER's draft decisions in respect of forecast opex and capex reflect only the expenditure required to achieve the reliability levels specified by ActewAGL Distribution's regulatory obligations and requirements in respect of quality and reliability; and
- that, thus, those expenditure allowances are inconsistent with the application of performance targets for the STPIS that are based on significantly higher historical reliability levels as proposed by the AER.

As the AEMC notes:[1069]

> *the STPIS represents an adjustment that is made after the AER has determined an appropriate base amount of expenditure to meet the expenditure objectives…it may be that the AER needs to amend the STPIS, for example, to reflect any step changes in the level of reliability used to determine the expenditure allowance from one regulatory period to the next.*

While acknowledging the views of the AEMC and AEMO that the STPIS requires reform in publishing its Stage 2 F&A Paper in January 2014, the AER decided there was inadequate time to review the national STPIS before finalising its determination for ActewAGL Distribution (we understand because of the consultation requirements under the Rules) and instead noted its intention to undertake a review of the national STPIS once the AEMO VCR Review and the AEMC

[1068] AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period, November 2014, Attachment 11: Service target performance incentive scheme*, November 2014, p. 11-14

[1069] AEMC 2013, *Rule Determination National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013*, 19 September 2013, p. 24

study were complete.[1070] This suggests that the AER is cognisant that the national STPIS needs review.

Nonetheless, the AER has not made any modifications to the national STPIS to address the inconsistency in the reliability levels reflected in expenditure allowances for the subsequent regulatory period and those reflected in the performance targets to apply in that period that arises from the AEMC's Rule change. This is despite the AEMC noting that:[1071]

> *the AER might need to amend the STPIS for DNSPs and TNSPs in light of the rule as made. It might not be able to do this in time for the first NSPs that the rule as made would apply to. However, AER has some flexibility under these schemes. For example, it can choose which parameters apply and the revenue at risk under the schemes. In addition it can choose not to apply the schemes.*

The AER's draft decision on STPIS makes no explicit mention of the change in the specification by the Rules of the reliability levels for which expenditure allowances are to fund a DNSP that occurred with effect from 26 September 2013. The AER has not amended the relevant performance targets to account for the fact that opex and capex allowances are now to be no more than the level considered necessary to comply with a relevant regulatory obligation or requirement, where these have been set by the body allocated that role.[1072] The AER has further not reflected that the expenditure an NSP includes in its regulatory proposal is no longer to be based on maintaining the NSP's existing levels of reliability, even where an NSP is performing above the required standards for these measures (as ActewAGL Distribution is).[1073]

While the AER considers it had insufficient time to amend the national STPIS, that does not justify applying the national STPIS to ActewAGL Distribution without modification. ActewAGL Distribution contends that the AER must make modifications to the performance targets to reflect the level of reliability for which ActewAGL Distribution is compensated through its expenditure allowances so that ActewAGL Distribution is provided with a reasonable opportunity to recover at least its efficient costs in light of the above Rule change.

[1070] AER 2014, *Stage 2 Framework and approach ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, January 2014, pp. 15 and 17

[1071] AEMC 2013, *Rule Determination National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013*, 19 September 2013, p. 33

[1072] AEMC 2013, *Rule Determination National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013*, 19 September 2013, p. 30

[1073] AEMC 2013, *Rule Determination National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013*, 19 September 2013, p. ii

The AER has failed to take into account that, in making its opex and capex decisions:

- it provides an allowance for ActewAGL Distribtution only to meet regulatory obligations or requirements (such as the minimum reliability standards required by the Supply Standards Code); and
- as ActewAGL Distribution has historically been exceeding such standards, it does not provide ActewAGL Distribution with a sufficient allowance to maintain reliability.

Therefore, the draft decision:

- imposes an expected loss on ActewAGL Distribution, in the form of a STPIS penalty, which is inconsistent with Clause 7A(2) of the NEL in that a reasonable opportunity has not been provided to ActewAGL Distribution to recover at least the efficient costs it incurs in providing direct control network services and complying with a regulatory obligation or requirement; and
- is inconsistent with Clause 3.2.1(2) of the national STPIS which states that "*The performance targets to apply during the regulatory control period… <u>must</u> be based on average performance over the past five regulatory years, modified by… <u>any other factors that are expected to materially affect network reliability performance</u>*." (emphasis added).

In relation to the AER's statements that:

- Clause 6.6.2 of the Rules requires that a STPIS must provide incentives to maintain and improve performance, and
- a fundamental principle underlying the STPIS is that it incentivises the distributors to achieve an efficient level of supply reliability in accordance with consumers' value of reliability,

ActewAGL Distribution notes that incentives are equivalent under the performance targets proposed by ActewAGL Distribution and the performance targets adopted by the AER in its draft decision. The reason for this is that incentives are determined by the incentive rates and are not affected at the margin by performance targets (though incentives may be affected by expectations about how performance targets will be set in future). By way of example, consider a situation in which a performance target is set at 100 and the incentive rate is set at $1 per unit change relative to the target for both rewards for improvements and penalties for deterioration in performance. A project that would cost $1 and would improve performance by 2 from 100 to 98, would result in a STPIS reward of $2 and a net reward of $1 (after subtracting the project cost). Suppose now the performance target was instead set at 95. By spending $1 on the project and improving its performance from 100 to 98, the NSP incurs a penalty of $3 (because 98 is higher than 95), but if it had not undertaken the project it would have incurred a penalty of $5.

So, the NSP receives a benefit of $2 (in the form of avoided penalties) and a net benefit of $1. The NSP faces the same financial incentive under both performance targets.

To address the AER's contention that:

- ActewAGL Distribution’s past expenditure should have a significant ongoing future effect on performance; and
- the opex and capex allowances that may be approved for ActewAGL Distribution’s future expenditure needs are not the most important determinant of its ability to meet performance targets,

ActewAGL Distribution has amended the performance targets proposed in its revised regulatory proposal to account for the effects of historical expenditure. This is discussed in Section 12.4.6.

Incentive rates

The AER's draft decision to set STPIS incentive rates based on the VCR estimated by AEMO, rather than on VCR evidence from the ACT as proposed by ActewAGL Distribution, is incorrect and unreasonable for the reasons discussed in turn below.

The AER lists a number of reasons why it prefers the VCR estimated by AEMO. ActewAGL Distribution responds to each of these reasons in Table 12.5 below. It is clear from this response that the AER has erred in placing reliance on the AEMO VCR Review in preference to ACT specific data.

Clause 6.6.2(3) of the Rules clearly requires the AER to take into account the circumstances of ActewAGL Distribution and the customers or end users that ActewAGL Distribution supplies. In particular, the draft decision is inconsistent with Clause 6.6.2(b)(3)(vi) of the Rules, which requires the AER to take into account the willingness of the customer or end user to pay for improved performance in the delivery of services.

ActewAGL Distribution contends, consistent with its submissions to AEMO, that VCR estimates at the NEM region level should not be used for applications that are specific to distribution networks in the ACT.[1074] The available evidence – namely AEMO’s VCR estimate for the New South Wales NEM region of around $38/kWh (excluding direct connects) and the estimate derived by ActewAGL Distribution for the ACT of around $67/kWh – suggests the value placed on reliability by customers in the ACT is different to the value placed on reliability by customers in New South Wales.

[1074] Attachment G13: ActewAGL 2013, *Value of customer reliability – Response to Directions Paper*, 3 July, p. 2

There are also logical reasons to expect that VCR would differ between ACT and New South Wales, for example, due to differences in climate and socioeconomic characteristics:

- the climate in the ACT is more extreme than the climate in the populated areas of New South Wales. Accordingly, the value of reliability in winter in the ACT is likely to be higher than in New South Wales;
- winter temperatures in the ACT are more comparable with temperatures in Tasmania – a NEM region for which AEMO found a statistically significant preference for avoiding winter outages (in contrast to its finding for the NSW NEM region);[1075]
- energy demand in the ACT has historically peaked in winter, whereas energy demand in NSW peaks in summer;
- the value of reliability in summer in the ACT is also likely to be relatively high, since mean daily maximum temperatures in January are greater in the ACT than they are in Sydney;[1076]
- mean annual income and the proportion of persons with post-school qualifications are higher in the ACT than in NSW ($60,987 versus $53,917 in 2012 dollars and 64.5 per cent versus 57.2 per cent, respectively),[1077] which some studies have found to be associated with a higher level of willingness to pay.[1078]
- Indeed, AEMO would appear to recognise that VCR could be expected to differ between ACT and New South Wales. In its Application Guide for VCR, "*AEMO acknowledges that regional VCR calculations produce collective values that encompass a range of different environments and circumstances.*" AEMO further states that "*[it] may be acceptable to use local knowledge to calculate a specific VCR for a given location.*"[1079] AEMO has separately encouraged ActewAGL Distribution to consider supplementing the state values with local knowledge that ActewAGL Distribution may have regarding the value

[1075] AEMO 2014, *Value of customer reliability review Final Report*, September, p20.

[1076] Based on mean historic temperatures taken for the airports at Sydney, Canberra and Launceston (which has a more severe winter than Hobart) using Bureau of Meteorology data.

[1077] Based on ABS Data by Region 2012.

[1078] See, for example, Attachment G9 – BJ McNair, J Bennett, DA Hensher, JM Rose (2011). Households' willingness to pay for overhead-to-underground conversion of electricity distribution networks. *Energy Policy* 39 (5), 2560-2567.

[1079] AEMO 2014, Value of customer reliability – Application guide, December, p9.

that its customers place on reliability of supply when assessing specific ACT based augmentations.[1080]

Table 12.5 AER reasons for preferring the AEMO VCR Review and ActewAGL Distribution response

AER reason	*ActewAGL Distribution response*
The revised AEMO VCR values are based on surveys undertaken in the middle of 2014, which would better reveal customers' current value of reliably compared to the 2003 NERA and the 2012 ANU studies.	The 2012 study of residential consumers by the ANU is a very recent study by the standards of choice modelling studies, which are generally not undertaken more frequently than once in five years due to the cost and complexity of the task.[1081]
The 2012 ANU study only surveyed residential customers, which cannot represent the entire customer class under ActewAGL's network. As AEMO found in the review, the VCR values for the commercial and agricultural sectors decreased significantly in recent years. This finding is not captured by the 2012 ANU study.	The non-residential component of ActewAGL Distribution's proposed VCR is based on the 2003 study by NERA. There is no evidence to suggest that this value has changed significantly since 2003: • Residential preferences were stable between the 2003 NERA and 2012 ANU studies in real terms.[1082] • The evidence noted by the AER in relation to changes in commercial VCR over time is based on a comparison of results from studies employing different methodologies. It is not clear to what extent the difference is due to changes in method as distinct from changes in underlying consumer preferences. The AER's reliance on this material is therefore unreasonable. • The non-residential sector in Canberra differs from other jurisdictions, with a large number of national institutions and federal public service customers who do value reliability.

[1080] Email from Nicola Falcon, Planning Specialist, AEMO to Ben McNair, Principal Economist, ActewAGL Distribution on 8 December 2014.

[1081] For example, AEMO states, "*In its letter to the COAG Energy Council, AEMO suggested a NEM-wide VCR survey be conducted once every five years… AEMO considers that a five year update strikes a balance between the costs involved in undertaking the survey and the consumer insights obtained from updating the values more frequently. The current survey took about 18 months to complete, and was labour intensive. It would not be practical or cost effective to undertake such a survey more regularly*." (AEMO 2014, Value of customer reliability – Application guide, December, p24)

[1082] See Attachment G11, pi-ii.

AER reason	*ActewAGL Distribution response*
The sample size of the AEMO VCR Review is significantly larger than those studies proposed by ActewAGL.	High levels of statistical significance were obtained in the models estimated by NERA and the ANU, which indicates that the sample size was sufficient.[1083] The ANU and NERA studies included many more respondents from the ACT than the AEMO VCR Review. The ANU study included 408 residential consumers, whereas the AEMO VCR Review included only 304 across all of New South Wales and ACT, which suggests only around 15 were from the ACT.[1084] The NERA study included 203 non-residential respondents, whereas we estimate the AEMO VCR Review included only around 21 business customers from the ACT.[1085] No valid ACT-specific VCR estimates for each customer type can therefore be derived from the AEMO data. Given the number of parameters being estimated, VCR estimates derived from these sample sizes would be statistically insignificant. The ANU and NERA sample sizes also covered a significantly greater proportion of the population for which they purport to estimate values (compared to the AEMO VCR Review). For example, the ANU study respondents represented 0.112 per cent of the population of the ACT, whereas the AEMO residential respondents in New South Wales and ACT represented just 0.004 per cent of the population of New South Wales and ACT. The sample size relative to population is therefore 29 times greater in the ANU study than in the AEMO VCR Review.

[1083] See Attachment G6a, p70 and Attachment G11, pp26-27.

[1084] Based on 2014 population estimates obtained from the Australian Bureau of Statistics (ABS) (Cat. No. 3101.0).

[1085] Based on 2013 gross business numbers obtained from the ABS (Cat. No. 8165.0).

AER reason	ActewAGL Distribution response
AEMO has engaged and consulted with stakeholders extensively.	The NERA and ANU studies: • were developed in consultation with consumer focus groups and in-depth interviews with consumers; • were refined based on feedback from respondents in pilot surveys; • used scenarios that were calibrated to each respondents' past bills or experience of supply interruptions; and • themselves represent engagement and consultation as the surveys included fields for comments. Further, the academic experts overseeing the studies consulted with leading authorities in choice modelling internationally at key stages of the process, including designing the survey instruments and estimating the choice models.[1086]

Lastly, the AER relies upon two unsubstantiated comments by Origin and the CCP. As these comments are not supported by evidence, little, if any, weight can reasonably be given to these comments by the AER in making its final decision, particularly in light of the evidence which has been provided by ActewAGL Distribution which is from rigorous and expert-reviewed choice modelling studies conducted in the ACT.

Neither of the stakeholder comments relied on by the AER relates directly to VCR. However, ActewAGL Distribution notes that the New South Wales study to which Origin refers estimated VCR at $95/kWh (in $2011-12),[1087] which is significantly higher than the VCR estimate proposed by ActewAGL Distribution in its regulatory proposal of $67/kWh (in $2014/15)[1088] and the VCR adopted by the AER in its draft decision of $38/kWh (in $2014/15).[1089] Therefore, Origin's reference to the AEMC study in New South Wales does not actually support the AER's draft decision to adopt a lower VCR than that proposed by ActewAGL Distribution.

[1086] See, for example, Attachment G11, p126.

[1087] AEMC 2012, Final Report – NSW Workstream, Review of Distribution Reliability Outcomes and Standards, August.

[1088] ActewAGL Distribution 2014, Regulatory Proposal 2015–19 Subsequent regulatory control period, June, p374.

[1089] AEMO 2014, Value of customer reliability review, Final Report, September.

Revenue at risk

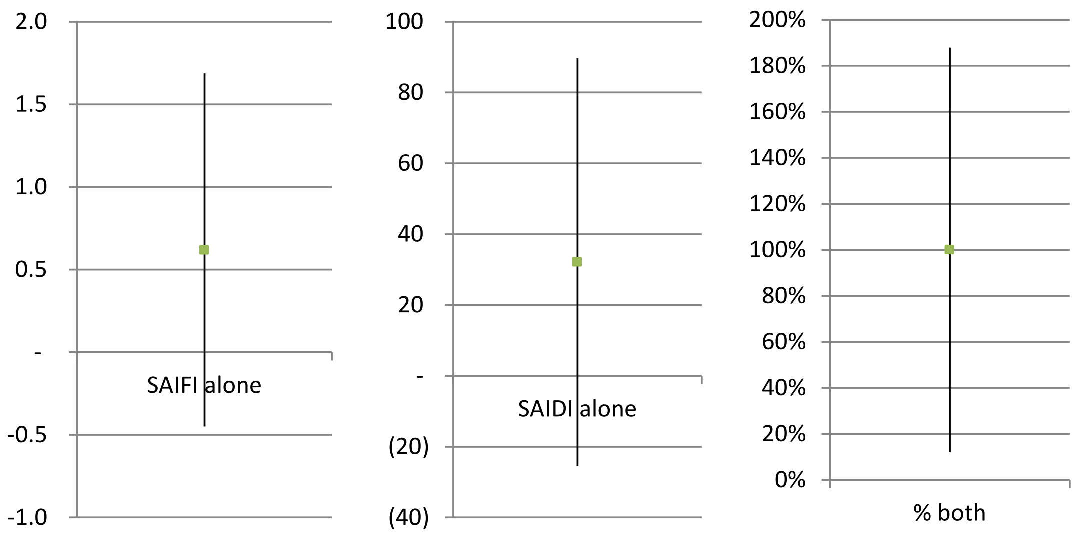
The appropriate level of revenue at risk depends on the levels of the performance targets and incentive rates. Under the combination of performance targets, incentive rates and the revenue requirement set in the AER's draft decision, the revenue at risk under the STPIS is effectively asymmetric, since the cap on annual rewards corresponds to infeasible levels of uSAIDI and uSAIFI. The threshold for limiting rewards is calculated in Attachment H16 and corresponds to:

- A reduction in uSAIFI alone from 0.62 to -0.45;
- A reduction in uSAIDI alone from 32.1 to -25.4; or
- A reduction in both uSAIFI and uSAIDI by 88 per cent (a reduction in uSAIFI to 0.07 events and uSAIDI to 4 minutes).

None of these reliability outcomes is technically feasible.[1090] The range of feasible performance levels over which revenue is at risk is effectively asymmetric, since rewards are limited by technical constraints at a much lower level than penalties are limited by the specification of revenue at risk under the STPIS.

[1090] uSAIFI and uSAIDI cannot be negative by definition. Perfect reliability, with zero supply interruptions, corresponds to zero levels of uSAIDI and uSAIFI. In practice, it would not be possible to reduce uSAIDI and uSAIFI by 88 per cent within the SRP. Even converting all of ActewAGL Distribution's overhead networks to underground networks, with their historically superior reliability performance, may not achieve this performance level and such a project would take several regulatory periods to complete.

Figure 12.3 Reliability performance corresponding to revenue at risk under AER draft decision



Exclusions

The AER states that it "*sought the revised 2003–08 unplanned SAIDI data from ActewAGL that correctly removed all exclusions in accordance with appendix D of the STPIS. We did not receive the required information from ActewAGL in time for this draft decision.*"[1091] ActewAGL Distribution notes that it sought clarification from the AER in relation to this statement and the AER indicated that it was inadvertently left in the document and should be disregarded.[1092]

1091 AER 2014, *AER Draft Decision, ActewAGL 2014-15 to 2018-19 regulatory control period*, November 2014, Attachment 11, p. 11-13. Similar comments appear on pp. 11-17 and pp. 11-18.

1092 Information request ACTEW AER 001 (Email from Usman Saadat (ActewAGL Distribution) to Kurt Stevens (AER) on Monday, 15 December 2014 12:08 PM and response from Kurt Stevens (AER) to Usman Saadat (ActewAGL Distribution) on Wednesday, 17 December 2014 4:48 PM)

12.4.6 ActewAGL Distribution revised proposal

Overview

ActewAGL Distribution continues to propose that the s-factor component of the national STPIS be applied to ActewAGL Distribution with the two modifications originally proposed with respect to the:

- performance targets for the reliability of supply component; and
- VCR used to set incentive rates for the reliability of supply component.

ActewAGL Distribution's revised proposal with respect to performance targets and incentive rates is set out below.

ActewAGL Distribution also proposes, in light of the draft decision on forecast opex and the revisions ActewAGL Distribution has made to its proposed performance targets in response to the draft decision, that a further modification be made to ensure the level of revenue at risk is symmetric, with the cap on annual rewards corresponding to feasible levels of uSAIFI and uSAIDI. Accordingly, ActewAGL Distribution proposes that the level of revenue at risk under the STPIS should now be set at ±2.5 per cent.

Performance targets

To address the AER's points that:

- ActewAGL Distribution’s past expenditure should have a significant ongoing future effect on performance; and
- the opex and capex allowances that may be approved for ActewAGL Distribution’s future expenditure needs are not the most important determinant of its ability to meet performance targets,

ActewAGL Distribution has amended the targets proposed in its revised regulatory proposal to account for the effects of historical expenditure.

The revised performance targets have been developed on the basis of the following assumptions:

- Weather-corrected reliability outcomes in 2014-19 are a function of existing assets as at 1 July 2014, capital expenditure in 2014-19, and controllable operating expenditure in 2014-19.
- The impact of each of these three components on reliability in a given year is proportionate to the component of the residual RAB in that year relating to existing assets (assets contained in the opening RAB as at 1 July 2014), the component of the residual RAB in that year relating to capex in the 2014-19 period, and controllable operating expenditure in that year, respectively.

- The existing assets as at 1 July 2014 have the effect of maintaining reliability at the average performance observed over the past five years.
- Capex in the 2014-19 period has the effect of aligning reliability with the minimum standards.
- Controllable operating expenditure has the effect of aligning reliability with the minimum standards.

Applying these assumptions gives the reliability performance estimates over the four years of the subsequent regulatory period shown in Table 12.6. The calculations supporting these targets are provided in Attachment H16.

Table 12.6 Unsmoothed reliability performance estimates

	2015-16	2016-17	2017-18	2018-19
SAIDI				
Urban	31.1	31.3	31.5	31.7
Short rural	46.0	45.8	45.6	45.4
SAIFI				
Urban	0.65	0.66	0.68	0.69
Short rural	0.95	0.96	0.98	0.99

In accordance with Clause 3.2.1(a) of the national STPIS, which states that the performance targets to apply during the regulatory control period must not deteriorate across regulatory years, ActewAGL Distribution has smoothed the reliability estimates by taking the average over the four years for the purpose of setting the performance targets under STPIS. ActewAGL Distribution's proposed targets are set out in Table 12.7.

Table 12.7 ActewAGL Distribution revised proposal on reliability performance targets under STPIS

	2015-16	2016-17	2017-18	2018-19
SAIDI				
Urban	31.3	31.3	31.3	31.3
Short rural	45.8	45.8	45.8	45.8
SAIFI				
Urban	0.66	0.66	0.66	0.66
Short rural	0.96	0.96	0.96	0.96

Figure 12.4 and Figure 12.5 compare the revised proposal on reliability performance targets for urban feeders with the corresponding targets in ActewAGL Distribution's regulatory proposal and the AER's draft decision.

Figure 12.4 Revised proposal on uSAIDI performance targets for urban feeders

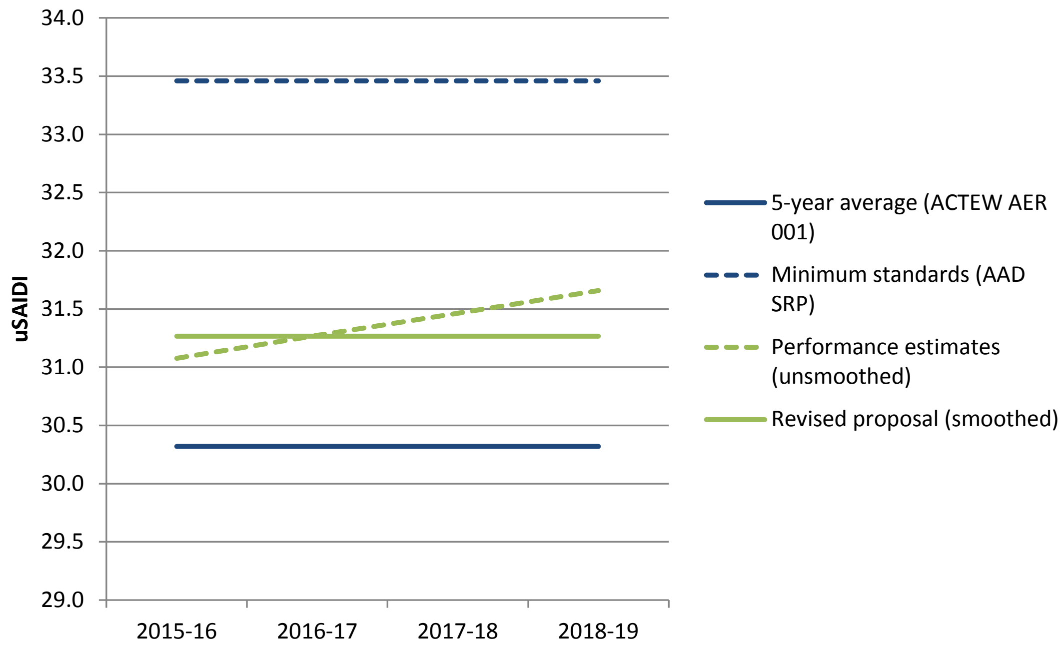
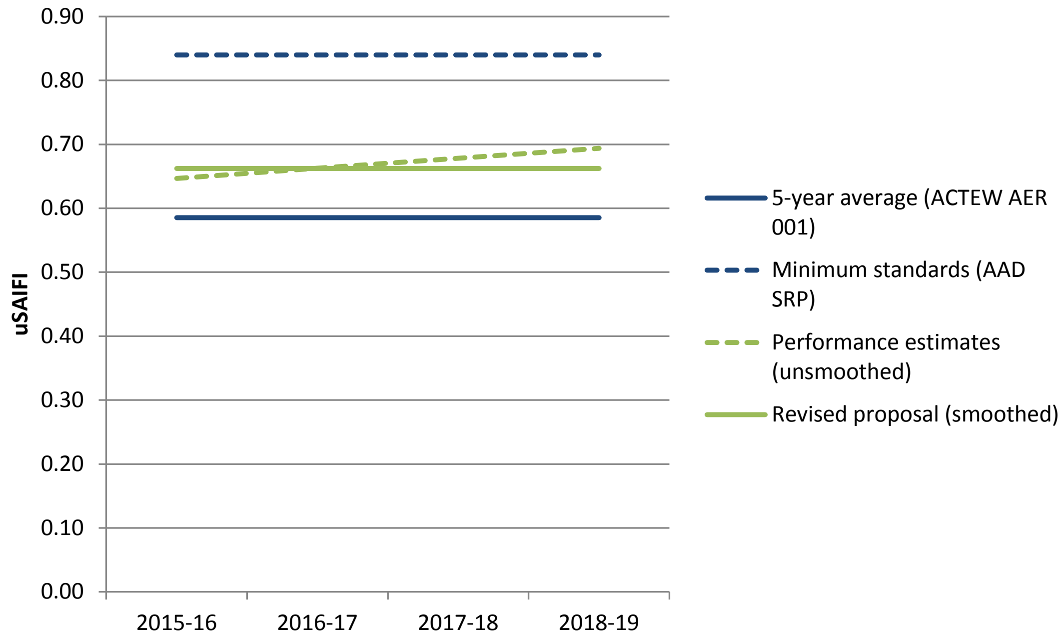


Figure 12.5 Revised proposal on uSAIFI performance targets for urban feeders



The revised targets are materially different from the targets in the AER's draft decision because the fact that the expenditure allowances provided by the AER are now based on regulatory obligations, as distinct from maintaining reliability as in the past, is a factor that is expected to materially affect network reliability over time and therefore must be recognised as a modification to ActewAGL Distribution's STPIS performance targets in accordance with clause 3.2.1(2) of the national STPIS, which states:

> *The performance targets to apply during the regulatory control period… must be based on average performance over the past five regulatory years, modified by the following: any other factors that are expected to materially affect network reliability performance.*

This proposal is consistent with the objectives set out in Clause 1.5 of the National STPIS for the reasons set out in Table 16.6 on page 370 of ActewAGL Distribution's regulatory proposal.

Incentive rates

ActewAGL Distribution maintains its proposal for reliability incentive rates to be based on an ACT-specific VCR of $67,258 per MWh ($2014/15). ActewAGL Distribution has updated its proposed incentive rates only to account for the revised consumption forecasts, revenue requirement and reliability performance targets in this revised proposal. These calculations are provided in Attachment H16.

Table 12.8 ActewAGL Distribution revised proposal on STPIS incentive rates

Item	*Amount*		*Source*
Average of smoothed revenue requirement ($nom)	175,993,661		Attachment H8
Feeder type	*Urban*	*Short rural*	
VCR ($2014-15 / MWh)	67,258	67,258	Regulatory proposal, Attachment F1
Weighting	0.97	0.92	National STPIS
Average annual energy consumption (MWh)	2,491,756	303,699	Attachment H16 and Attachment H17
Average USAIDI target	31.3	45.8	Attachment H16
Average USAIFI target	0.66	0.96	Attachment H16

Table 12.9 Revised proposal on reliability incentive rates

	Urban	*Short rural*
per cent per unit change in USAIDI	0.08915	0.01057
per cent per unit change in USAIFI	4.33944	0.54773

Revenue at risk

ActewAGL Distribution noted that the range of reliability levels over which rewards and penalties would apply under the AER's draft decision on the STPIS would effectively be asymmetric.

As the appropriate level of revenue at risk depends on the levels of the performance targets and incentive rates, ActewAGL Distribution's original proposal that the revenue at risk under the STPIS should be set at ±5 per cent was dependent on its then proposed performance targets. As it has been necessary for ActewAGL Distribution to revise its proposal in relation to performance targets in response to the AER's draft decision on the STPIS, it has also been necessary for ActewAGL Distribution to reassess the appropriate level of revenue at risk as a consequence of the draft decision.

As discussed above, the approach of the AER of applying a ±5 per cent level of revenue at risk, together with the other aspects of its draft decision on the STPIS including in particular its proposed performance targets, is effectively asymmetric. This is because rewards are limited by technical constraints, whereas penalties are limited only by the specification of the revenue at risk. ActewAGL Distribution contends that the level of revenue at risk must be symmetric. To ensure the level of revenue at risk would be symmetric, with the cap on annual rewards corresponding to feasible levels of uSAIFI and uSAIDI, ActewAGL Distribution proposes that the level of revenue at risk under the STPIS instead be set at ±2.5 per cent. Clause 6.6.2(3)(iii) of the Rules states that in implementing the national STPIS the AER must take into account the past performance of the distribution network. ActewAGL Distribution's network is the most reliable in Australia in terms of unplanned interruptions and as a consequence scope for further reliability improvement is limited and subject to rapidly increasing marginal cost. At the same time, the AER is proposing significant reductions to ActewAGL Distribution's forecast expenditure allowances for the 2014-19 period relative to its past expenditure allowances. The AER must take this into account when setting the revenue at risk under STPIS to ensure that the range of feasible reliability levels that are subject to rewards or penalties is symmetric.

12.5 DMIS

12.5.1 Introduction

This Section responds to the AER's draft decision on how the DMIS is to apply to ActewAGL Distribution which is set out in Attachment 12 to the draft decision.

ActewAGL Distribution accepts the AER's draft decision.

12.5.2 The relevant legal and regulatory framework for the DMIS

Clause 6.12.1(9) of the Rules provides that one of the constituent decisions by the AER on which the distribution determination for ActewAGL Distribution for the subsequent regulatory period is predicated is a decision on how any applicable DMIS is to apply to ActewAGL Distribution.

Clause 11.56.4(b) to (f) of the Rules provides for the application of specified provisions of current Chapter 6 of the Rules on the basis that the TRP is to be treated as either the last regulatory year of the 2009-14 regulatory control period or the first regulatory year of the subsequent regulatory period. Clause 11.56.4(g), in turn, provides that nothing in clause 11.56.4 has the effect of actually rendering the TRP as the first regulatory year of the subsequent regulatory period and, except for the purposes of the application of paragraphs (b) to (f) in accordance with their terms, the TRP must be treated as a regulatory control period that is separate to the subsequent regulatory period.

Clause 6.12.1(9) of current Chapter 6, which provides for the making of the constituent decision on how any applicable DMIS is to apply to ActewAGL Distribution, is not referred to in paragraphs (b) to (f) of clause 11.56.4. It follows that, in making the distribution determination for ActewAGL Distribution for the subsequent regulatory period, the AER's decision is in respect of how any applicable DMIS is to apply to ActewAGL Distribution in the subsequent regulatory period.[1093]

Clause 6.6.3(a) of the Rules permits the AER to develop and implement an incentive scheme or incentive schemes to provide incentives for DNSPs to consider economically efficient alternatives to building more network. In so doing, the AER is required to have regard to the matters set out in clause 6.6.3(b) of the Rules.

In 2008, the AER published the DMIS for the ACT and NSW 2009 distribution determinations, which is comprised of a demand management innovation allowance (DMIA) scheme and a D-factor scheme.[1094] The DMIA scheme is comprised of two parts: Part A, which provides for an innovation allowance to be incorporated into each DNSP's revenue allowance for opex for each regulatory year of the regulatory control period and Part B which compensates DNSPs for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A. Part B of the DMIA is not relevant where an average revenue cap form of

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[1093] Clause 11.56.3(a)(4) of the Rules required the distribution determination made by the AER for ActewAGL Distribution for the TRP to specify the D-factor scheme and DMIS that applied to ActewAGL Distribution under its distribution determination for the 2009-14 regulatory control period applies to ActewAGL Distribution in the TRP subject to such modifications as are set out in the framework and approach paper that is published in respect of the SRP for ActewAGL Distribution. Clause 11.56.3(h)(3) of the Rules provides that a framework and approach paper that is published in respect of the SRP for ActewAGL Distribution may specify in relation to the distribution determination for the TRP, the modifications to be made to an incentive scheme referred to in paragraph (a)(4).

[1094] AER 2008, *Demand management incentive scheme for the NSW and ACT 2009 distribution determinations D-factor scheme*, 29 February 2008; AER 2008, *Demand management incentive scheme for the NSW and ACT 2009 distribution determinations Demand management innovation allowance scheme*, 28 November 2008 control applies to standard control services. Part A of the DMIA, but not Part B of the DMIA or the D-factor scheme, applied to ActewAGL Distribution in the 2009-14 regulatory control period pursuant to its distribution determination for that period.

Clause 6.8.1(b)(2)(vi) of the Rules provides that a framework and approach paper that applies in respect of a distribution determination must set out the AER's proposed approach, for that distribution determination, to the application to ActewAGL Distribution of any applicable DMIS. Clause 11.56.4(l) of the Rules provides for the AER to make its framework and approach paper for ActewAGL Distribution for the subsequent regulatory period in two stages, with the matter here referred to being addressed in the 'Stage 2 F&A paper'.

The AER's Stage 2 F&A Paper proposed that Part A of the DMIA continue to apply to ActewAGL Distribution from the TRP onwards.[1095]

12.5.3 ActewAGL Distribution's proposal

In ActewAGL Distribution's regulatory proposal for the subsequent regulatory period, it proposed that the AER continue to apply Part A of the DMIA for the subsequent regulatory period consistent with the AER's approach proposed in the Stage 2 F&A Paper.[1096]

As the AER stated in the Stage 2 F&A Paper its intention to develop and implement a new DMIS for the subsequent regulatory period but that doing so was dependent on the progress of the Rule change process arising from the AEMC's Power of Choice review, ActewAGL Distribution mentioned that it was unclear how a new scheme could apply once the distribution determination for the subsequent regulatory period had been made. To address this concern, ActewAGL proposed that a pass through event be included in the AER's distribution determination for the subsequent regulatory period to allow recovery of any change in costs, including incentives, incurred by ActewAGL Distribution in implementing demand management projects under a new scheme. ActewAGL Distribution's proposed pass through event, the AER's draft decision on that event and ActewAGL Distribution's revised proposal on that event are discussed in Chapter 12 of this revised regulatory proposal.

[1095] AER 2014, *Stage 2 Framework and approach ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, January 2014, p. 32

[1096] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 378

12.5.4 AER draft decision

In its draft decision, the AER determines to accept ActewAGL Distribution's proposal and continue to apply Part A of the DMIA for the subsequent regulatory period consistent with the AER's approach proposed in the Stage 2 F&A Paper and adopted for the TRP by the AER's placeholder determination.[1097]

It further determines that the current DMIA amount of $0.1 million ($ 2014/15) per annum will continue to apply in the subsequent regulatory period.[1098]

12.5.5 ActewAGL Distribution's response

ActewAGL Distribution accepts the AER’s draft decision.

[1097] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 12*, p. 12-7

[1098] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 12*, p. 12-7

13 Classification of services

13.1 Introduction

In this Chapter 13 ActewAGL Distribution responds to the AER's draft decision on the classification of distribution services set out in Attachment 13 to the draft decision.

In its draft decision, the AER retains the classification of ActewAGL Distribution's distribution services for the subsequent regulatory period proposed in its Stage 1 F&A Paper subject to the following modifications:[1099]

- the AER accepts ActewAGL Distribution's proposal that large scale embedded generator connection services (above 30 kWs) should be classified as alternative control services (as part of the AER's ancillary network services service group);
- the AER also accepts ActewAGL Distribution's proposal to add network studies to the list of services in the AER's ancillary network services service group (with the consequence that these are classified as alternative control services);
- the AER unilaterally classifies the administration costs for type 5 and type 6 meter transfers as an additional alternative control service; and
- it unilaterally classifies the recovery of residual type 5 or type 6 meter capital costs as an additional standard control service.

The AER does not accept, however, ActewAGL Distribution's proposal to add services provided at above the least cost technically acceptable standard (LCTAS) at a customer's request to the list of services in the AER's ancillary network services service group.

ActewAGL Distribution is content with the AER's draft decision to include large scale embedded generator connection services and network studies in the ancillary network service group. It also accepts the AER's draft decision that there is no need to add services provided at above the LCTAS at a customer's request to the list of services in the AER's ancillary network services service group.

ActewAGL Distribution agrees with the AER that unforeseen circumstances justify departing from the AER's proposed classification of the type 5 and 6 metering services to be provided by ActewAGL Distribution set out in its Stage 1 F&A Paper, as is required by clause 6.12.3(b) of the

[1099] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 13*, November, p. 13-7

Rules to enliven an AER discretion to effect such a departure in making its constituent decision on classification. ActewAGL Distribution considers that the making by the Standing Council on Energy and Resources (SCER) (now the COAG Energy Council) of its Rule change request in respect of metering contestability[1100] and the resultant initiation by the AEMC of its Expanding competition in metering and related services Rule change process,[1101] both of which post-dated the publication by the AER of the Stage 1 F&A Paper in March 2013, constitute such unforeseen circumstances.

While ActewAGL Distribution agrees that the AER should classify an additional type 5 and 6 metering service so as to provide for the impending introduction of metering contestability, however, ActewAGL Distribution considers that the AER's draft decision to classify the recovery of residual type 5 or type 6 meter capital costs as a discrete, additional standard control service is legally impermissible, constitutes an incorrect exercise of discretion and an unreasonable decision in all the circumstances.

ActewAGL Distribution sets out its contentions in support of this proposition in Chapter 14 of this revised regulatory proposal in responding to the AER's draft decision on the control mechanism for metering services. This is because the AER sets out the reasons for its draft decision to classify the recovery of the residual value of any type 5 or 6 meter that is made redundant due to a customer switching meters as a standard control service in Attachment 16 to the draft decision (which details the AER's draft decision on the control mechanisms for alternative control services). Accordingly, this Chapter 13 should be read together with section 14.3 of Chapter 14 of this revised regulatory proposal.

ActewAGL Distribution instead proposes that a single additional type 5 and 6 metering service, described as follows, should be classified as an alternative control service (in the metering services (types 5 to 7) service group):

> *Types 5 and 6 meter transfer service comprised of the services required to complete a customer initiated switch (meter transfer) from a DNSP provided type 5 or 6 meter.*

ActewAGL Distribution's proposed additional type 5 and 6 metering service would enable it to recover:

[1100] SCER 2013, *Introducing a new framework in the National Electricity Rules that provides for increased competition in metering and related services Rule change request*, October (provided as Attachment G14 to this revised regulatory proposal).

[1101] AEMC 2014, *Notice under the National Electricity Law*, 17 April

- its administrative costs relating to the administrative requirement to change records to reflect the changed status, the return of the meter and the processing costs of relaying this information; and
- the residual value of any type 5 or 6 meter that is made redundant due to a customer switching meters.

13.2 The relevant legal and regulatory framework for the classification of distribution services

Clause 6.12.1(1) of the Rules provides that one of the constituent decisions by the AER on which the distribution determination for ActewAGL Distribution for the subsequent regulatory period is predicated is a decision on the classification of the services to be provided by ActewAGL Distribution during the course of the regulatory control period.

Clause 6.2.1 (a) of the Rules provides that the AER may classify a distribution service to be provided by ActewAGL Distribution as a direct control service or a negotiated distribution service. Clause 6.2.2(a) of the Rules provides that direct control services must be further divided into standard control services and alternative control services. Clauses 6.2.1(b) and 6.2.2(b) provide that, in classifying distribution services and direct control services, the AER may group distribution services together for the purpose of classification and, if it does so, a single classification made for the group applies to each service comprised in the group as if it had been separately classified.

Clause 6.2.1(c) of the Rules provides that, in classifying a distribution service, the AER must have regard to:

- the form of regulation factors set out in section 2F of the NEL;
- the form of regulation (if any) previously applicable to the service;
- the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction); and
- any other relevant factor.

Clause 6.2.2(c) of the Rules provides that, in classifying direct control services as standard control services or alternative control services, the AER must have regard to:

- the potential for development of competition in the relevant market and how the classification might influence that potential;
- the possible effects of the classification on administrative costs of the AER, ActewAGL Distribution and users or potential users;

- the regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made;
- the desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction);
- the extent to which the costs of providing the relevant service are directly attributable to the person to whom the service is provided; and
- any other relevant factor.

Clauses 6.2.1(d) and 6.2.2(d) provide that, in classifying distribution services and direct control services that have previously been subject to regulation under the present or earlier legislation, the AER must act on the basis that, unless a different classification is clearly more appropriate, there should be no departure from a previous classification or, if there has been no previous classification, the classification should be consistent with the previously applicable regulatory approach.

Pursuant to clause 6.2.3 of the Rules, the classification forms part of the distribution determination and operates for the regulatory control period for which the distribution determination is made.

Clause 11.56.4(b) to (f) of the Rules provides for the application of specified provisions of current Chapter 6 of the Rules on the basis that the transitional regulatory period is to be treated as either the last regulatory year of the 2009-14 regulatory control period or the first regulatory year of the subsequent regulatory period. Clause 11.56.4(g), in turn, provides that nothing in clause 11.56.4 has the effect of actually rendering the transitional regulatory period as the first regulatory year of the subsequent regulatory period and, except for the purposes of the application of paragraphs (b) to (f) in accordance with their terms, the transitional regulatory period must be treated as a regulatory control period that is separate to the subsequent regulatory period.

The provisions of current Chapter 6 set out above are not referred to in paragraphs (b) to (f) of clause 11.56.4. It follows that the AER's decision on the classification of the services to be provided by ActewAGL Distribution for the purposes of its distribution determination for the subsequent regulatory period applies only in the subsequent regulatory period.[1102]

[1102] Clause 11.56.3(a)(1) of the Rules required the distribution determination made by the AER for ActewAGL Distribution for the TRP to specify the same classification of distribution services as that which was decided for the distribution determination for ActewAGL Distribution for the 2009-14 regulatory control period, except to the extent the framework and approach paper that is published in respect of the SRP for ActewAGL Distribution

Clause 6.12.3(b) of the Rules provides that the classification of distribution services must be as set out in the relevant framework and approach paper unless the AER considers that unforeseen circumstances justify departing from the classification as set out in that paper.

Clause 6.8.1(b)(2)(i) of the Rules relevantly provides that a framework and approach paper that applies in respect of a distribution determination must set out the AER's decision, for the purposes of that determination, on the classification of distribution services. Clause 11.56.4(l) of the Rules provides that the AER must make the framework and approach paper(s) that apply in respect of a distribution determination for ActewAGL Distribution for the subsequent regulatory period in two stages, with the matters referred to here to be addressed in the 'Stage 1 F&A Paper'.

The AER's proposed approach to the classification of the services to be provided by ActewAGL Distribution during the subsequent regulatory period set out in the AER's Stage 1 Framework and approach paper for ActewAGL for the transitional regulatory period and subsequent regulatory period published in March 2013 (Stage 1 F&A Paper) is summarised in Table 13.1 below.[1103]

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provides otherwise, in which case the classification must (to that extent) be as supplemented or modified in accordance with that framework and approach paper. Clause 11.56.3(h)(1) of the Rules provides that a framework and approach paper that is published in respect of the SRP for ActewAGL Distribution may specify in relation to the distribution determination for the TRP, the classification of distribution services for the TRP (which must be the same as the classification of distribution services that is specified for the SRP by any framework and approach paper).

[1103] AER 2013, *Stage 1 Framework and approach paper ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2014 to 30 June 2019*, March, p. 27

Table 13.1 AER's proposed classification of distribution services for ActewAGL Distribution

AER service group	*Proposed classification of distribution services*	*Proposed classification of direct control services*
Network services	Direct control	Standard control
Connection services	Direct control	Standard control
Metering services		
Types 1 to 4	Unclassified	
Types 5 to 6	Direct control	Alternative control
Type 7	Direct control	Alternative control
Ancillary network services	**Direct control**	**Alternative control**

Appendix B to the AER's Stage 1 F&A Paper set out a complete list of the services to be provided by ActewAGL Distribution and the AER's proposed classification of each of those services.[1104]

13.3 ActewAGL Distribution's proposal

In its regulatory proposal for the subsequent regulatory period, ActewAGL Distribution accepted the service classifications set out in the AER's Stage 1 F&A paper and proposed the following clarifications and additions:[1105]

- large scale embedded generator connection services should be classified as alternative control services;
- network studies should be added to the list of services in the AER's ancillary network services service group (and thus classified as alternative control services); and
- services provided at above the least cost technically acceptable standard (LCTAS) at a customer's request should also be added to the AER's ancillary network services service group (and thus classified as alternative control services).

[1104] AER 2013, *Stage 1 Framework and approach paper ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2014 to 30 June 2019*, March, pp. 52-54

[1105] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, June (resubmitted 10 July 2014), pp. 329, 342 and 350-353

ActewAGL Distribution also proposed that the list of ancillary network services in the AER's Stage 1 F&A Paper be disaggregated further for pricing purposes and set out a complete list of its proposed ancillary network services in Attachment F3 to its regulatory proposal.[1106]

13.4 AER draft decision

In its draft decision, the AER retains the classification of ActewAGL Distribution's distribution services for the subsequent regulatory period proposed in its Stage 1 F&A Paper subject to the following modifications:[1107]

- the AER accepts ActewAGL Distribution's proposal that large scale embedded generator connection services (above 30 kWs) should be classified as alternative control services (as part of the AER's ancillary network services service group);
- the AER also accepts ActewAGL Distribution's proposal to add network studies to the list of services in the AER's ancillary network services service group (with the consequence that these are classified as alternative control services);
- the AER unilaterally classifies the administration costs for type 5 and type 6 meter transfers as an additional alternative control service; and
- it unilaterally classifies the recovery of residual type 5 or type 6 meter capital costs as an additional standard control service.

The AER does not accept, however, ActewAGL Distribution's proposal to add services provided at above the LCTAS at a customer's request to the list of services in the AER's ancillary network services service group.

The AER agrees with ActewAGL Distribution that, while large scale embedded generator connection services constitute connection services which are classified as standard control services, a standard control service classification is not appropriate and they should instead be included in the ancillary network services group and so classified as alternative control services.[1108] The AER further concludes that unforeseen circumstances justify this departure

[1106] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, June (resubmitted 10 July 2014), p. 342

[1107] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 13*, November, p. 13-7

[1108] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 13*, November, pp. 13-11 to 13-12

from the proposed classification set out in the Stage 1 F&A Paper because the implementation of the new Rules with respect to connections meant ActewAGL Distribution was considering its connection policy, in the course of which the transitional issues resulting in the need for classification of this service were identified, only after the AER's Stage 1 F&A Paper was published.

The AER does not consider it necessary to further disaggregate the services provided by ActewAGL Distribution that fall within the ancillary network services service group.[1109] It nonetheless adds network studies to that services group. It does not add services provided at above the LCTAS at a customer's request, however, on the basis that, while connection services are classified as standard control services, the AER's Connection charge guideline published in June 2012[1110] provides for a customer that requests a connection service to be provided at above the LCTAS to pay the additional cost of providing the service to this higher standard.

The AER concludes that, for the purposes of clause 6.12.3(b) of the Rules, ActewAGL Distribution's regulatory proposal for the subsequent regulatory period gives rise to an unforeseen circumstance that justifies the departure from the AER's proposed classification of the type 5 and 6 metering services to be provided by ActewAGL Distribution set out in its Stage 1 F&A Paper.[1111] Specifically, the AER observes that:[1112]

> *…at the time of releasing our Stage 1 F&A, it was not possible for us to foresee ActewAGL's approach to dealing with customers switching meter providers. The need to classify two additional metering services is evident from ActewAGL's proposal. We are therefore satisfied that this constitutes an unforeseen circumstance that justifies us departing from the classification set out in our Stage 1 F&A.*

[1109] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 13*, November, p. 13-12

[1110] AER 2012, *Connection charge guideline for electricity retail customers Under chapter 5A of the National Electricity Rules*, June

[1111] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 13*, November, p. 13-10

[1112] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 13*, November, p. 13-10

The AER describes the additional type 5 and 6 metering service it classifies as an alternative control service (in the metering services (types 5 to 7) service group) as follows:[1113]

> *Types 5 and 6 metering ancillary administrative services for meter transfer: Administrative services required to complete a customer initiated switch (meter transfer) from a DNSP provided type 5 or 6 meter.*

The AER's stated reasons for the classification of this additional type 5 and 6 metering service are as follows:[1114]

> *Although ActewAGL did not propose administrative charges associated with customers switching to an alternative metering provider, we consider it prudent to indicate how we would classify such a service should ActewAGL propose to recover such costs in its revised proposal. These costs, if substantiated, would be directly attributable to a customer seeking to switch meters. On this basis we are satisfied the service 'meter transfers' should be classified as an alternative control service.*

The AER describes the additional type 5 and 6 metering service it classifies as a standard control service as follows:[1115]

> *Recovery of residual value of any type 5 or 6 meter that is made redundant due to a customer switching meters.*

The AER's stated reasons for the classification of this additional type 5 and 6 metering service are as follows:[1116]

> *An exit fee can be designed to recover capital costs associated with metering assets made redundant when a customer switches to an alternative metering provider. This was the approach the NSW distribution businesses adopted. Although ActewAGL did not propose an exit fee, we consider it prudent to indicate how we would classify such a service as this needs to be set out in our distribution determination. In classifying this service, we consider the residual metering*

[1113] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 13 - Appendix A*, November, p. 13-13

[1114] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 13*, November, p. 13-11

[1115] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 13 - Appendix A*, November, p. 13-13

[1116] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 13*, November, p. 13-11

capital costs should be recovered as a standard control service. As explained in attachment 16, these costs should be recovered from all customers because to do otherwise would create a barrier to the development of a competitive market for the provision of metering services. The NEL and NER require us to have regard to the development of competition in deciding appropriate service classification[s].

Appendix A to Attachment 13 to the AER's draft decision sets out a complete list of the services to be provided by ActewAGL Distribution during the subsequent regulatory period and the AER's draft decision on the classification of each of those services.[1117]

13.5 ActewAGL Distribution's response and revised proposal

ActewAGL Distribution is content with the AER's draft decision to include large scale embedded generator connection services and network studies in the ancillary network service group.

ActewAGL Distribution also accepts the AER's draft decision that there is no need to add services provided at above the LCTAS at a customer's request to the list of services in the AER's ancillary network services service group. The purpose of ActewAGL Distribution's proposal with respect to these services was to ensure that it was clear that customers requesting services of this kind should pay the additional cost of providing the relevant connection services to the higher standard. ActewAGL Distribution accepts the AER's point that its Connection charge guideline (in section 2.1.3) establishes that customers requesting a service of a higher standard *"should also pay the additional cost of providing the service to the standard requested"*.[1118] ActewAGL Distribution further observes that its approved Connection Policy also explains that customers requesting a service above the LCTAS will be required to pay the additional cost.[1119]

ActewAGL Distribution agrees with the AER that unforeseen circumstances justify departing from the AER's proposed classification of the type 5 and 6 metering services to be provided by ActewAGL Distribution set out in its Stage 1 F&A Paper, as is required by clause 6.12.3(b) of the Rules to enliven an AER discretion to effect such a departure in making its constituent decision on classification.

[1117] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 13 - Appendix A*, November, pp. 13-13 to 13-15

[1118] AER 2012, *Connection charge guideline for electricity retail customers Under chapter 5A of the National Electricity Rules*, June, section 2.1.3, p. 10

[1119] ActewAGL Distribution 2014, *ActewAGL Distribution Connection Policy Version 2.0*, June, pp. 12, 15-16

ActewAGL Distribution disagrees, however, with the AER's characterisation of those unforeseen circumstances. ActewAGL Distribution considers that it is the making by the SCER (now the COAG Energy Council) of its Rule change request in respect of metering contestability[1120] and the resultant initiation by the AEMC of its Expanding competition in metering and related services Rule change process,[1121] both of which post-dated the publication by the AER of the Stage 1 F&A Paper in March 2013, that constitutes the unforeseen circumstances that justify the departure from the AER's proposed classification of ActewAGL Distribution's type 5 and 6 metering services. ActewAGL Distribution does not consider the approach adopted in its regulatory proposal constitutes (or is capable of constituting) unforeseen circumstances of the kind contemplated by clause 6.12.3(b).

ActewAGL Distribution agrees that the AER should classify an additional type 5 and 6 metering service in making its constituent decision on the classification of the services to be provided by ActewAGL Distribution during the subsequent regulatory period so as to provide for the impending introduction of metering contestability. However, ActewAGL Distribution considers that the AER's draft decision to classify the recovery of residual type 5 or type 6 meter capital costs as a discrete, additional standard control service (and so provide for the transfer of a portion of its metering RAB to the standard control services RAB during the subsequent regulatory period and the smeared recovery of that RAB value through general network tariffs from the general customer base[1122]) is legally impermissible, constitutes an incorrect exercise of discretion and an unreasonable decision in all the circumstances.

ActewAGL Distribution sets out its contentions in support of this proposition in Chapter 14 of this revised regulatory proposal in responding to the AER's draft decision on the control mechanism for metering services. This is because the AER sets out the reasons for its draft decision to classify the recovery of the residual value of any type 5 or 6 meter that is made redundant due to a customer switching meters as a standard control service in Attachment 16 to the draft decision (which details the AER's draft decision on the control mechanisms for alternative control services). Accordingly, this Chapter 13 should be read together with section 14.3 of Chapter 14 of this revised regulatory proposal.

[1120] SCER 2013, *Introducing a new framework in the National Electricity Rules that provides for increased competition in metering and related services Rule change request*, October

[1121] AEMC 2014, *Notice under the National Electricity Law*, 17 April

[1122] See AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p. 16-26

ActewAGL Distribution instead proposes that a single additional type 5 and 6 metering service, described as follows, should be classified as an alternative control service (in the metering services (types 5 to 7) service group):

> *Types 5 and 6 meter transfer service comprised of the services required to complete a customer initiated switch (meter transfer) from a DNSP provided type 5 or 6 meter.*

ActewAGL Distribution's proposed additional type 5 and 6 metering service would enable it to recover both:

- its administrative costs relating to the administrative requirement to change records to reflect the changed status, the return of the meter and the processing costs of relaying this information; and
- the residual value of any type 5 or 6 meter that is made redundant due to a customer switching meters.

This is discussed further in section 14.3 of Chapter 14 of this revised regulatory proposal.

14 Alternative control services

14.1 Introduction

In this Chapter 14 ActewAGL Distribution responds to the AER's draft decision on the control mechanisms for alternative control services set out in Attachment 16 to its draft decision. After detailing the legal and regulatory framework applicable to the control mechanism(s) for alternative control services in section 14.2 below, ActewAGL Distribution responds to:

- the AER's draft decision on the control mechanism for metering services in section 14.3 below; and
- the AER's draft decision on the control mechanisms for ancillary network services (both fee based and quoted) in section 14.4 below.

Those responses are briefly summarised in turn below.

14.1.1 Metering services

In making its draft decision on the control mechanism for metering services, the AER:

- decides that from 1 July 2015 there should be two categories of charges for alternative control metering services, being upfront capital charges and annual metering charges, and two schedules of annual charges, one for existing customers (the annual charges for whom should include capital cost recovery) and the other for new customers (who have made an upfront capital contribution and the annual charges for whom should not recover any capital cost);
- accepts ActewAGL Distribution’s proposal to use a limited building block approach to determine annual metering charges, but does not accept the proposed values for the capex and opex building blocks and substitutes its own values; and
- rejects ActewAGL Distribution's proposal that, depending on the outcome of the relevant Rule change process, its proposed structure for metering charges be supplemented by the establishment of an exit fee, during the SRP, to recover the costs associated with customers switching to alternative meter providers when the new Rules and arrangements for contestable metering are implemented, and decides to instead classify residual meter capital costs as a standard control service and recover these through network tariffs. More specifically, the AER proposes:

- *an 'adjustment of moving residual capital costs back into [the] standard control services RAB would happen on an annual basis through a b-factor adjustment (see attachment 14 for how it would work)';*[1123] *and*
- *'to introduce a tolerance limit which would cap how much extra revenue may be added to DUoS tariffs on an annual basis' to address the potential for price volatility if a large volume of customers churn in any given year.*[1124]

ActewAGL Distribution accepts the AER's draft decision on the proposed structure of metering charges, that is, to introduce up-front capital charges to recover the cost of new and upgraded meters and two schedules of annual charges, one for existing customers and another for new customers, from 1 July 2015. However, ActewAGL Distribution:

- does not accept the AER's draft decision to approve $14.0 million in opex and substitute that amount for AAD's proposed $19.4 million ($2013/14), and instead proposes a revised opex building block of $16.0 million ($2013/14), including debt raising costs;
- does not accept the AER's draft decision to approve $7.9 million in net capex and substitute that amount for AAD's proposed $33.5 million ($2013/14), and instead proposes a revised capex building block of $12.7 million ($2013/14);
- contends that the AER's draft decision to classify the recovery of residual type 5 or type 6 meter capital costs as a discrete, additional standard control service, and so provide for the transfer of a portion of ActewAGL Distribution's metering RAB to the standard control services RAB during the SRP and the smeared recovery of that RAB value through general network tariffs from the general customer base, is legally impermissible, constitutes an incorrect exercise of discretion and an unreasonable decision in all the circumstances;
- instead proposes that a single additional type 5 and 6 metering service, described as follows, should be classified as an alternative control service (in the metering services (types 5 to 7) service group):

> *Types 5 and 6 meter transfer service comprised of the services required to complete a customer initiated switch (meter transfer) from a DNSP provided type 5 or 6 meter.*

[1123] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, p. 16-26

[1124] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, pp. 16-26 to 16-27

- thus, maintains its original proposal that exit fees, for ActewAGL Distribution's proposed types 5 and 6 meter transfer service, should be used to recover the residual value of meters, and associated costs, when customers switch to alternative providers; and
- proposes that, if the AER continues to reject exit fees (as it has in the Draft Decision), then a modified version of the AER’s B factor adjustment should apply (to allow full recovery of residual meter values, plus relevant transfer administration costs, via network charges).

ActewAGL Distribution contends that the AER's classification of the recovery of residual metering capital costs as a standard control service and proposed use of the B_t term in the formulae for the control mechanism for standard control services for *'moving residual capital costs back into [the] standard control services RAB'* is properly characterised as a sham designed to evade the unambiguous requirements of the Rules. This is for reasons which include:

- the discretion conferred on the AER by the Rules in respect of classification is one to classify a service provided by means of, or in connection with, ActewAGL Distribution's distribution system and does not empower the AER to classify the recovery of a category or type of costs divorced from any service to be provided by ActewAGL Distribution (or indeed, differently to the services to be provided by ActewAGL Distribution to which those costs relate), as the AER purports to do in classifying the recovery of the residual value of any type 5 or 6 meter that is made redundant due to a customer switching meters as a standard control service;
- whereas the Rules prohibit the inclusion in the RAB for standard control services, and the recovery through charges for those services, of the value of assets that are not used by ActewAGL Distribution in the provision of standard control services, the value of the redundant meter assets that the AER would have transferred to the standard control services RAB during the SRP cannot properly be said to be used by ActewAGL Distribution in the provision of *any* service; and
- whereas the Rules do not permit the addition to the RAB for standard control services during a regulatory control period of the value of assets not previously included therein, the AER expressly states that it seeks to effect just such a result through its classification of the recovery of residual type 5 or type 6 meter capital costs as a standard control service and its proposed B factor adjustment.

While ActewAGL Distribution considers that the NEO preferable decision is to establish exit fees, for its proposed types 5 and 6 meter transfer service, to recover the residual value of meters when customers switch to alternative providers, ActewAGL Distribution considers that the following modifications to the AER's proposed B factor adjustment are necessary if the AER maintains its draft decision so as to address the risk that would otherwise exist that the tolerance limits would operate to preclude ActewAGL Distribution from recovering the residual capital costs of stranded meters:

- residual meter values should be recovered via network charges from the start of the 2015-19 period, rather than progressively from 1 July 2017 (as under the AER's draft decision);
- the residual value of all metering assets in ActewAGL Distribution's metering RAB should be divided by four and recovered in the B factor in the formulae for the standard control services control mechanism over the 4 years of the SRP; and
- no tolerance limits should apply to the annual adjustment.

14.1.2 Ancillary network services

In making its draft decision on the control mechanism for fee based ancillary network services, the AER approves ActewAGL Distribution's proposed 2015/16 fees but does not approve its proposed fees for the remaining regulatory years of the SRP. This is because the AER does not approve ActewAGL Distribution's proposed annual escalation rate of 1.5 per cent and instead applies its own labour escalation rates. The AER also decides a fee for the final regulatory year of the SRP (but not any X factor) for two fee based ancillary network services for which ActewAGL Distribution did not propose a fee, being new underground service connection - greenfield and new underground connection service - greenfield metering only.

ActewAGL Distribution does not accept:

- the AER's draft decision on labour escalation rates to apply to alternative control services for the SRP. ActewAGL Distribution's reasons for not accepting the AER's labour escalation rates are set out in section 3.5.3 of Chapter 3 of this revised regulatory proposal; or
- the AER's draft decision to apply a fee for ActewAGL Distribution's new underground service connection - greenfield and greenfield metering only - services, as the application of fees for these services would be inconsistent with ActewAGL Distribution's Connection Policy, as approved by the AER in Attachment 18 to the draft decision.

ActewAGL Distribution's revised proposed X factors for fee based ancillary network services are set out in section 14.3.3.1 below. They have been calculated on the basis of ActewAGL Distribution's revised proposed labour escalation rates detailed in Chapter 3 to this revised regulatory proposal, rather than the 1.5 per cent escalation rate determined by the AER in its draft decision, for the reasons advanced in respect of these revised proposed labour escalation rates in Chapter 3. The revised labour rates are provided in section 14.3.3.1 below.

It was also necessary for ActewAGL Distribution to revise its proposed fees for those of its ancillary network services the provision of which involve or necessitate new meters, as a consequence of the AER's draft decision, accepted by ActewAGL Distribution in this revised regulatory proposal, that upfront charges should be used from 1 July 2015 to recover the capital cost of new or upgraded meters.

In addition, if the AER maintains its draft decision to significantly reduce allowed revenues from standard control services in making its final decision, ActewAGL Distribution proposes full cost recovery for all fee based ancillary network services from 2015/16, instead of a gradual transition to full cost recovery over the course of the SRP, because it would not then be able to subsidise the provision of fee based ancillary network services during the SRP.

In making its draft decision on the control mechanism for quoted ancillary network services, the AER approves ActewAGL Distribution's proposed form of control, being Price = labour + contractor services + materials + other costs + risk margin, but does not approve ActewAGL Distribution's proposed labour rates for office support delivery and senior technical officer, on the basis that these rates exceed the efficient benchmark level recommended by its consultants, and instead decides its own approved maximum labour rates for these labour types.

ActewAGL Distribution is content with the AER's approval of its proposed form of control for quoted ancillary network services. However ActewAGL Distribution does not agree with the AER's proposed labour rates for quoted services.

14.2 The relevant legal and regulatory framework for control mechanism(s) for alternative control services

Clause 6.12.1(12) and (13) of the Rules provides that the constituent decisions by the AER on which the distribution determination for ActewAGL Distribution for the SRP is predicated include (amongst others):

- a decision on the form of the control mechanisms for alternative control services (to be in accordance with the relevant framework and approach paper) and on the formulae that give effect to those control mechanisms; and
- a decision on how compliance with a relevant control mechanism is to be demonstrated.

Clause 6.2.5(a) of the Rules provides that a distribution determination is to impose controls over the prices of direct control services, the revenue to be derived from direct control services or both. Clause 6.2.5(b) provides that the control mechanism may consist of a schedule of fixed prices, caps on the prices of individual services, caps on the revenue to be derived from a particular combination of services, tariff basket price control, revenue yield control or a combination of any of these.

Clause 6.2.5(d) of the Rules provides that, in deciding on a control mechanism for alternative control services, the AER must have regard to:

- the potential for development of competition in the relevant market and how the control mechanism might influence that potential;
- the possible effects of the control mechanism on administrative costs of the AER, ActewAGL Distribution and users or potential users;
- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination;
- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and
- any other relevant factor.

Clause 6.2.6(b) and (c) of the Rules provides that the control mechanism for alternative control services must have a basis stated in the distribution determination and may (but need not) utilise elements of Part C (with or without modification).

Clause 11.56.4(b) to (f) of the Rules provides for the application of specified provisions of current Chapter 6 of the Rules on the basis that the TRP is to be treated as either the last regulatory year of the 2009-14 regulatory control period or the first regulatory year of the SRP. Clause 11.56.4(g), in turn, provides that nothing in clause 11.56.4 has the effect of actually rendering the TRP as the first regulatory year of the SRP and, except for the purposes of the application of paragraphs (b) to (f) in accordance with their terms, the TRP must be treated as a regulatory control period that is separate to the SRP.

The provisions of current Chapter 6 set out above are not referred to in paragraphs (b) to (f) of clause 11.56.4. It follows that the AER's constituent decisions on the control mechanism for alternative control services and the formulae for that control mechanism, and how compliance with that control mechanism is to be demonstrated, apply only in the SRP.[1125]

[1125] Clause 11.56.3(a)(6) of the Rules required the distribution determination made by the AER for ActewAGL Distribution for the TRP to specify the same control mechanisms for alternative control services as those which were decided for the distribution determination for ActewAGL Distribution for the 2009-14 regulatory control period, except to the extent the framework and approach paper that is published in respect of the SRP for ActewAGL Distribution provides otherwise in accordance with clause 11.56.3(h)(2) of the Rules, in which case the relevant control mechanisms must be as set out in that framework and approach paper. Clause 11.56.3(h)(2) provides that a framework and approach paper that is published in respect of the SRP for ActewAGL Distribution may specify in relation to the distribution determination for ActewAGL Distribution for the TRP, the form of, and formulae to give effect to, the control mechanism for distribution services (which must be the same as the form and formulae that are specified in the SRP by any framework and approach paper) where that paper specifies a

Clause 6.12.3(c) and (d) of the Rules provides that:

- the form of the control mechanisms must be as set out in the relevant framework and approach paper; and
- the formulae that give effect to those control mechanisms must be as set out in the relevant framework and approach paper unless the AER considers that unforeseen circumstances justify departing from the formulae as set out in that paper.

Clause 6.8.1(b)(1)(i) and (2)(ii) of the Rules relevantly provides that a framework and approach paper that applies in respect of a distribution determination must set out the AER's decision, for the purposes of that determination, on the form (or forms) of the control mechanisms and the AER's proposed approach to the formulae that give effect to those control mechanisms. Clause 11.56.4(l) of the Rules provides that the AER must make the framework and approach paper(s) that apply in respect of a distribution determination for ActewAGL Distribution for the SRP in two stages, with the matters referred to here to be addressed in the 'Stage 1 F&A Paper'.

In its Stage 1 framework and approach paper published in March 2013 (Stage 1 F&A Paper), the AER decided to apply caps on the prices of individual services as the form of control for ActewAGL Distribution's alternative control services in the SRP and proposed to apply the following formulae to alternative control services:[1126]

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classification for distribution services for the TRP that is different to that decided for the distribution determination for ActewAGL Distribution for the 2009-14 regulatory control period.

[1126] AER 2013, *Stage 1 Framework and approach paper ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, March 2013, pp. 10, 28 and 39-42. As the AER explained in its *Discussion paper Formulae for control mechanisms - Revised Matters relevant to the framework and approach for NSW and ACT DNSPs 2014-19* of February 2013 (at pp. 12-13), where services were classified as alternative control services in the 2009-14 regulatory control period and continue to be so classified in the TRP and SRP, the control mechanism for alternative control services applies only in the SRP (i.e. "t" is 1, … , 4) because clause 11.56.3(j) of the Rules provides that the prices for alternative control services that are provided by ActewAGL Distribution during the TRP must be the prices that applied as at the end of the 2009-14 regulatory control period escalated by CPI as at that time. By contrast, where services were not classified as alternative control services in the 2009-14 regulatory control period, the control mechanism for alternative control services applies in the TRP and the SRP (i.e. "t" is 1, … , 5) because clause 11.56.3(j) of the Rules does not apply.

Services currently classified as alternative control services and which continue to be classified as alternative control services

$\bar{p}_i^t \geq p_i^t$ *i=1,…n and t=1,…4,*

$\bar{p}_i^t = \bar{p}_i^{t-1} \ (1 + CPI_t)(1 - X_i^t)$

Where:

$\bar{p}_i^t$ *is the cap on the price of service i in year t.*

p_i^t *is the price of service i in year t.*

CPI_t *is the percentage increase in the consumer price index. To be decided in the final decision.*

X_i^t *is the X-factor for service i in year t. To be decided in the final decision.*

$\bar{p}_i^1$ *is the cap on the price of service i in the first year of the subsequent regulatory control period. To be decided in the final decision.*

Services currently classified as standard control services and which may be reclassified as alternative control services

$\bar{p}_i^t \geq p_i^t$ *i=1,…n and t=1,…5*

$\bar{p}_i^t = \bar{p}_i^{t-1} \ (1 + CPI_t)(1 - X_i^t)$

Where:

$\bar{p}_i^t$ *is the cap on the price of service i in year t.*

p_i^t *is the price of service i in year t.*

CPI_t *is the percentage increase in the consumer price index. To be decided in the final decision.*

X_i^t *is the X-factor for service i in year t. To be decided in the final decision.*

$\bar{p}_i^1$ *is the cap on the price of service i in the transitional regulatory control period.*

The AER stated that the basis of the control mechanism for alternative control services - that is, whether prices would be set using a building block approach or another method - would be determined in the distribution determination and the prices for certain of the ancillary network services would be determined on a quoted basis.[1127]

[1127] AER 2013, *Stage 1 Framework and approach paper ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, March, p. 39

In its Stage 2 framework and approach paper published in January 2014 (Stage 2 F&A Paper), the AER clarified the ancillary network services for which it proposed to set prices on a quoted basis and stated that these prices would be derived from their relevant input costs (e.g. labour rate, material cost) and, for each year of the regulatory control period, the price of each quoted service would be set by substituting the input cost of each for $\overline{p}_i^{t-1}$ in the formulae for the control mechanism set out in the Stage 1 F&A Paper.[1128]

Finally, clauses 11.56.3(h)(4) and 11.56.4(l)(2) of the Rules provide that the "Stage 2 F&A paper" that is published in respect of the SRP for ActewAGL Distribution may specify in relation to the distribution determination for ActewAGL Distribution for the TRP the manner in which the prices that may be charged for alternative control services during the SRP are to be adjusted to account for any over or under recovery of revenue earned from the provision of those services during the TRP. The AER's Stage 2 F&A Paper is, however, silent on the making of adjustments of this kind to prices for alternative control services for the SRP.

14.3 Metering services

14.3.1 ActewAGL Distribution's proposal

In its regulatory proposal for the SRP, ActewAGL Distribution:

- accepted the AER's decision in the Stage 1 F&A Paper to apply caps on the prices of individual services as the form of control for ActewAGL Distribution's metering services in the SRP;[1129]
- proposed a limited building block approach to determining the price caps to apply to each metering service;[1130]
- proposed a simple pricing structure involving annual charges to recover the costs of providing the metering services;[1131] and

[1128] AER 2014, *Stage 2 Framework and approach ActewAGL Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, January, p. 11

[1129] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 330-331

[1130] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 331-339

- noted that it may be necessary to propose, during the SRP, a new exit fee to recover the costs associated with customers switching to alternative meter providers when the new Rules and arrangements for contestable metering are implemented depending on the outcome of that Rule change process.[1132]

In the regulatory proposal, ActewAGL Distribution emphasised the high degree of uncertainty regarding future policy and regulatory settings for metering.[1133]

14.3.2 AER draft decision

In its draft decision on ActewAGL Distribution's proposal for the control mechanism for metering services, the AER:[1134]

- gives effect to its decision in the Stage 1 F&A Paper to apply price caps on individual services as the form of control for metering services;
- consistent with the proposed formulae for the control mechanism for alternative control services set out in its Stage 1 F&A Paper, specifies the formula for the control mechanism for metering services to be:

$$\bar{p}_i^t \geq p_i^t \qquad i=1, \ldots, n \text{ and } t=1, 2, 3, 4$$

$$\bar{p}_i^t = \bar{p}_i^{t-1} (1 + CPI_t)(1 - X_i^t)$$

Where:

$\bar{p}_i^t$ *is the cap on the price of service i in year t. However, for 2015-16 this is the price as determined in Appendix A.1.*

p_i^t *is the price of service i in year t.*

1131 ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 339-340

1132 ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 340-341

1133 ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), pp. 340-341

1134 AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, pp. 16-20 to 16-21 and 16-35

CPI_t is the percentage increase in the consumer price index. It is calculated as follows:

The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the December Quarter immediately preceding the start of regulatory year t;

divided by

The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the December Quarter immediately preceding the start of regulatory year t-1;

minus one.

X_i^t *X is zero*

- rejects ActewAGL Distribution's proposed structure of metering charges, pursuant to which there is one schedule of annual charges, and instead decides that from 1 July 2015 there should be:
  - two categories of charges for alternative control metering services, being upfront capital charges and annual metering charges; and
  - two schedules of annual charges, one for existing customers (the annual charges for whom should include capital cost recovery) and the other for new customers (who have made an upfront capital contribution and the annual charges for whom should not recover any capital cost);
- accepts ActewAGL Distribution's proposal to use a limited building block approach to determine annual metering charges, but does not accept the proposed values of the capex and opex building block components. In particular, the AER does not accept:
  - ActewAGL Distribution's proposed capex building block, allowing $7.9 million in net capex for annual metering charges instead of ActewAGL Distribution's proposed $33.5 million ($2013/14), because of its cost assessment and its decision that new and upgraded meter capital costs are to be recovered via up-front charges rather than through annual metering charges imposed on all meter service users; and
  - ActewAGL Distribution's proposed opex building block, allowing $14.0 million in opex for annual metering charges instead of the proposed $19.4 million ($2013/14), because it rejects two of the three proposed step changes, makes an adjustment to the base year opex and adopts different escalators; and
- sets out its substitute annual charges and upfront charges for 2015/16 in Table 16.15 and Table 16.16 respectively in section A.1.3 to Appendix A to Attachment 16 to the

draft decision. In approving annual charges for the purposes of its draft decision (and setting out annual charges in Table 16.15 to Appendix A), the AER approves only one schedule of annual charges notwithstanding its draft decision that there should be two schedules of annual charges, one for existing customers and another for new customers.[1135] No reason is provided for this in the draft decision.

In addition, the AER rejects ActewAGL Distribution's proposal that, depending on the outcome of the Rule change process, its proposed structure for metering charges be supplemented by the establishment of an exit fee, during the SRP, to recover the costs associated with customers switching to alternative meter providers when the new Rules and arrangements for contestable metering are implemented.[1136] The AER instead proposes, in its draft decision on service classification, to classify residual metering capital costs as a standard control service and recover these through network tariffs.

The AER considers that the recovery of the metering RAB from existing customers through annual metering charges will support the transition to competition by providing customers and potential entrants a transparent signal of the avoidable cost of switching to unregulated metering.[1137] Of its decision to introduce up-front capital charges from 1 July 2015, the AER says:[1138]

> *We require this change to facilitate competition. When implemented, it should help level the competitive playing field for new and upgraded meters. This is by shifting how the capital costs for new and upgraded meters are recovered, from the annual metering services charge, where costs are smeared across all customers, to an upfront payment which new entrants to the market may compete with.*

While the AER accepts that the setting of individual exit fees based on the remaining economic value of the meter (which would vary with the capability of the meter (i.e. the meter type) and its remaining life) so as to recover the residual metering capital cost where an existing customer

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[1135] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p. 16-21 and Appendix A, section A.1.3 (Metering Services), pp. 16-52 to 16-53, Table 16.15

[1136] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p. 16-21

[1137] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p. 16-26

[1138] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p. 16-28

churns to a different meter provider would be economically efficient, it nonetheless decides that residual metering capital costs should be recovered *'through general network tariffs i.e. smeared across the general customer base'* because:[1139]

- it is not feasible in practice to set individual exit fees of this kind having regard to:
    - information constraints, in that most DNSPs do not record the information about meter asset type or age at the customer level that would be required to set individual exit fees that provide an economically efficient investment signal; and
    - the fact that the amount DNSPs are entitled to recover based on their regulated metering costs may not correspond to the remaining economic value of the meter - that is, regulated metering costs may not be efficient - because of the absence of competition; and
- there is general stakeholder consensus that residual capital costs that arise when a customer changes meter provider should be classified as a standard control service.

The AER therefore proposes an *'adjustment of moving residual capital costs back into [the] standard control services RAB would happen on an annual basis through a b-factor adjustment (see attachment 14 for how it would work)'*.[1140] To address the potential for price volatility if a large volume of customers churn in any given year, the AER proposes *'to introduce a tolerance limit which would cap how much extra revenue may be added to DUoS tariffs on an annual basis'*.[1141]

The AER considers this approach is to be preferred on the basis of a consideration of the matters set out in clause 6.2.5(d) of the Rules in respect of the control mechanism for alternative control services.[1142]

[1139] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p. 16-26

[1140] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p. 16-26

[1141] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, pp. 16-26 to 16-27

[1142] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, pp. 16-27 to 16-29

Finally, ActewAGL Distribution observes that the AER does not, in its draft decision, purport to make any constituent decision on how compliance with the control mechanism for metering services is to be demonstrated.

14.3.3 ActewAGL Distribution's response and revised proposal

Overview

ActewAGL Distribution accepts the AER's draft decision on the proposed structure of metering charges, that is, to introduce up-front capital charges to recover the cost of new and upgraded meters and two schedules of annual charges, one for existing customers and another for new customers, from 1 July 2015. However, ActewAGL Distribution:

- does not accept the AER's draft decision to substitute ActewAGL Distribution's proposed capex and opex building blocks (to be used to determine the annual charges) with its own values;
- contends that the AER's draft decision to classify the recovery of residual type 5 or type 6 meter capital costs as a discrete, additional standard control service, and so provide for the transfer of a portion of ActewAGL Distribution's metering RAB to the standard control services RAB during the SRP and the smeared recovery of that RAB value through general network tariffs from the general customer base, is legally impermissible, constitutes an incorrect exercise of discretion and an unreasonable decision in all the circumstances;
- instead proposes that a single additional type 5 and 6 metering service, described as follows, should be classified as an alternative control service (in the metering services (types 5 to 7) service group):

  Types 5 and 6 meter transfer service comprised of the services required to complete a customer initiated switch (meter transfer) from a DNSP provided type 5 or 6 meter.

- thus, maintains its original proposal that exit fees, for ActewAGL Distribution's proposed types 5 and 6 meter transfer service, should be used to recover the residual value of meters and associated transfer costs when customers switch to alternative providers; and
- proposes that, if the AER continues to reject exit fees (as it has in the draft decision), then a modified version of the AER's B factor adjustment should apply (to allow full recovery of residual meter values via network charges).

Recovery of residual metering capital costs

ActewAGL Distribution contends that the AER's draft decision to classify the recovery of residual type 5 or type 6 meter capital costs as a discrete, additional standard control service, and so provide for the transfer of a portion of ActewAGL Distribution's metering RAB to the standard control services RAB during the SRP and the smeared recovery of that RAB value through general network tariffs from the general customer base, is legally impermissible, constitutes an incorrect exercise of discretion and an unreasonable decision in all the circumstances.

ActewAGL Distribution contends that the AER's draft decision is legally impermissible (and thus an incorrect exercise of discretion and an unreasonable decision in all the circumstances) for 3 reasons as follows.

First, the discretion conferred on the AER by the Rules in respect of the constituent decision on classification is one to classify a distribution service or direct control service to be provided by ActewAGL Distribution.[1143] Each of these terms are, in essence, defined in the NEL and the Rules to mean *'a service provided by means of, or in connection with, a* distribution system*'*.[1144] For the purposes of the relevant definitions, the word 'service' takes its ordinary and natural meaning, being 'an act of helpful activity'; 'the supplying … of any articles, commodities, activities, etc., required or demanded'.[1145] It follows that it is not open to the AER to classify the recovery of a category or type of costs divorced from any service to be provided by ActewAGL Distribution (or, indeed, differently to the services to be provided by ActewAGL Distribution to which those costs relate), as it does in purporting to classify the recovery of the residual value of any type 5 or 6 meter that is made redundant due to a customer switching meters as a standard control service.

Secondly, the Rules prohibit the inclusion in the RAB for standard control services, and the recovery through charges for those services, of the value of assets that are not used by ActewAGL Distribution in the provision of standard control services. Clause 6.5.1(a) of the Rules, in particular, defines the RAB for standard control services to be *'the value of those assets that are used by [ActewAGL Distribution] to provide standard control services, but only to the extent that they are used to provide such services'*, while clause S6.2.1(e)(8) of the Rules permits the inclusion in the RAB of the value of an asset not previously used to provide standard control services but only where that asset is now to be used to provide standard control services. In circumstances where a metering asset, used by ActewAGL Distribution until that time in the provision of alternative control services, becomes redundant as a consequence of a customer initiated meter transfer, that asset cannot be said to be used by ActewAGL Distribution thereafter in the provision of *any* service (whether a standard control service or otherwise).

[1143] Clauses 6.2.1(a) and 6.2.2(a) of the Rules

[1144] Chapter 10 Rules' definitions of 'distribution service'and 'direct control service', section 2(1) NEL definitions of 'direct control service' and 'electricity network service', and section 2B NEL definition of 'direct control network service'

[1145] Macquarie Online Dictionary definition of 'service'

Even if the AER's classification of the 'recovery of residual value of any type 5 or 6 meter that is made redundant due to a customer switching meters' as a standard control service was legally permissible (which it is not for the reason already noted above), this would not assist to render permissible the AER's attempt to transfer the portion of ActewAGL Distribution's metering RAB attributable to that meter to the standard control services RAB. This is because the stranded meter could not properly be said to be *used by ActewAGL Distribution in providing* any service or even in the recovery of the residual capital cost.

Thirdly, the Rules do not permit the addition to the RAB for standard control services during the regulatory control period of the value of assets not previously included therein. This is evident from the provisions of clauses S6.2.1(e), including in particular paragraphs (6) to (8), and S6.2.3(e), which establish that the addition or removal of an asset to the RAB for standard control services can only occur at the beginning of a regulatory control period (and not during a regulatory control period) except where the asset is forecast to be disposed of during the regulatory control period. This is unsurprising given that the scheme of the Rules is that the classification of services is to apply unchanged for the duration of a regulatory control period (see, for example, clause 6.2.3) and, as already discussed, the RAB for standard control services is to include the value of only those assets used to provide services classified as standard control services during the relevant period.

The AER's classification of the recovery of residual metering capital costs as a standard control service and proposed use of the B_t term in the formulae for the control mechanism for standard control services for *'moving residual capital costs back into [the] standard control services RAB'* is, thus, properly characterised as a sham designed to evade the unambiguous requirements of the Rules. It is not authorised by the Rules and is not in accordance with law.

Further and in any event, even if (contrary to ActewAGL Distribution's contentions) the AER's draft decision to classify the recovery of residual type 5 or type 6 meter capital costs as a discrete, additional standard control service, and so provide for the transfer of a portion of ActewAGL Distribution's metering RAB to the standard control services RAB during the SRP and the smeared recovery of that RAB value through general network tariffs from the general customer base, is in accordance with law, that decision nonetheless constitutes an incorrect exercise of discretion and an unreasonable decision in all the circumstances for the following reasons:

- The AER's draft decision cannot be reconciled with the scheme of the Rules (discussed above).
- The policy objective that motivates the AER to make such a decision cannot be reconciled with the policy views expressed by the SCER (now the COAG Energy Council)

in requesting the Rule change to introduce metering contestability or by the AEMC in its Consultation paper on that Rule change request. Specifically, in its Rule change request, SCER proposed the following:[1146]

> *Where another party becomes the Metering Coordinator for a connection point that has an existing type 5 or type 6 metering installation, there is provision for a reasonable exit fee determined by the AER:*
>
> - *based on the average depreciated value of the stock of the LNSP's existing Type 5 or 6 meters (this is for simplicity and administrative ease, as an alternative to attempting to determine the age of the actual meter at each individual customer's premises);*
> - *which may include efficient and reasonable costs of processing the customer transfer to another Metering Coordinator; and*
> - *the AER should determine whether a cap on exit fees is appropriate and, if so, the level of the cap.*

Similarly, in its Consultation paper on the Rule change request, the AEMC observed:[1147]

> *The objective of an exit fee is to help the local distribution network business to recover the stranded (sunk) costs of its existing meters. An appropriate, clearly defined and transparent exit fee for accumulation or manually read interval meters would be expected to encourage competition and more efficient investment in advanced metering.*

- In any event, a policy decision to depart from the policy views expressed to date by policy makers is better left to the AEMC in making its Competition in metering and related services Rule change determination, rather than the AEMC's policy role being usurped by the AER as occurs in the Draft Decision, particularly where (as in the Draft Decision) that policy decision is not reconcileable with the existing Rules.
- Whereas the AER concludes that it is not feasible in practice to set individual exit fees based on the remaining economic value of the meter (as required for economic efficiency) because of information constraints, ActewAGL Distribution contends that

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[1146] SCER 2013, *Introducing a new framework in the National Electricity Rules that provides for increased competition in metering and related services Rule change request*, October, p. 12 (provided as Attachment G14 to this revised regulatory proposal)

[1147] AEMC 2014, *Consultation Paper National Electricity Amendment (Expanding Competition in Metering and Related Services) Rule 2014*, 17 April 2014, p. 51 (provided as Attachment G15 to this revised regulatory proposal) information constraints are not a practical impediment to the calculation of exit fees. The SCER (now COAG Energy Council) provided guidance in its Rule change request on the calculation of exit fees, proposing that the fee determined by the AER should be reasonable and:

> *based on the average depreciated value of the stock of the LNSP's existing Type 5 or 6 meters (this is for simplicity and administrative ease, as an alternative to attempting to determine the age of the actual meter at each individual customer's premises.*[1148]

- Further, the AER has approved exit fees, to cover both asset related and administrative costs, for SA Power Networks.[1149]
- The AER is not satisfied that the amount distributors are entitled to recover (based on actual costs) corresponds to the remaining economic value of a meter. This is because regulated metering costs may not be efficient because the network operators have not faced competitive pressures.[1150] However, ActewAGL Distribution contends that the regulated metering costs can be taken to be efficient. ActewAGL Distribution's regulated metering costs have been subject to detailed scrutiny in successive regulatory reviews by the AER and previously the Independent Competition and Regulatory Commission (ICRC). In determining the regulatory allowances for metering, the AER must, in accordance with the expenditure criteria in the Rules, have been satisfied that the costs are efficient.
- ActewAGL Distribution considers that the AER errs in concluding that there is stakeholder consensus that residual capital costs that arise when a customer changes meter provider should be classified as a standard control service. The AER refers to views expressed at its metering workshop on 11 September 2011.[1151] However, ActewAGL Distribution understands that a range of views were expressed at the

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[1148] SCER 2013, *Introducing a new framework in the National Electricity Rules that provides for increased competition in metering and related services, Rule change request*, October 2013, p. 11

[1149] SA Power Networks 2014*, Annual pricing proposal 2014/15*, p. 87, as approved and published by the AER on 17 June 2014 (see AER 2014, *Statement of Reasons, SA Power Networks electricity distribution network, Approval of 2014-15 pricing proposal*)

[1150] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p. 16-26

[1151] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p. 16-26

workshop. The AER did not publish a summary of workshop outcomes or views expressed.[1152] The AER did not seek written submissions, and therefore does not have a sound basis for concluding that there is stakeholder consensus that its proposed approach is appropriate.

- Whereas the AER concludes that the recovery of residual metering asset capital costs through exit fees would create a barrier to the development of competition for the provision of metering services, ActewAGL Distribution considers that the AER's approach of smearing cost recovery across the general customer base is not the NEO preferable decision because the costs to economic efficiency resulting from the incentive for inefficient overinvestment delivered by the AER's approach outweigh the benefits of fostering competition noted by the AER. These costs to economic efficiency are noted by the AER in its draft decision in the following terms:[1153]

  > *We acknowledge that our decision to classify residual capital costs as a standard control service does risk increased meter switching. We do not know what the actual efficient exit fee should be for each customer because we do not know the type and age of every meter, but given that these are all functioning meters, it is likely that there is some remaining economic life and therefore the efficient fee would be a positive amount. Our alternative approach therefore risks faster entry than otherwise i.e some meters being replaced even though they have significant remaining economic value, because our alternative exit fee (based on the incremental administration cost alone) is below the efficient exit fee.*

  The AER's reliance on the intent of policy makers to increase competition in metering services as the basis for disregarding the likelihood of inefficient overinvestment under the AER's approach[1154] is surprising, given that the AER disregards the preference of those same policy makers (discussed above) that residual capital costs be recovered through exit fees.

- ActewAGL Distribution maintains its position that transparent exit fees will encourage efficient decisions on the supply and use of metering services and facilitate an efficient

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[1152] Following the workshop the AER published, on its website, a list of attendees and the slides presented by the AER.

[1153] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, pp. 16-27 to 16-28

[1154] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p. 16-28

transition to competition. Exit fees are therefore preferable, in terms of promoting the NEO and consistency with the revenue and pricing principles, to the AER's alternative of smearing residual metering costs across all network users.

Accordingly, ActewAGL Distribution proposes that a single additional type 5 and 6 metering service, being a types 5 and 6 meter transfer service, be classified as an alternative control service and maintains its position in its regulatory proposal for the SRP that exit fees, payable for ActewAGL Distribution's proposed types 5 and 6 meter transfer service, are the appropriate way to recover the costs associated with customers switching to alternative providers when contestability is introduced, including both the residual value of the stranded meter and administrative costs relating to the meter transfer. This position is consistent with the SCER (now COAG Energy Council) Rule change request, which (as already noted) proposed that exit fees should be determined by the AER, to ensure that NSPs would have "minimal stranding risk".[1155]

ActewAGL Distribution accepts the AER's view that an exit fee should be proposed prior to the start of the SRP (rather than during the SRP). Consistent with the guidance provided by the SCER (now COAG Energy Council) in its Rule change request, ActewAGL Distribution's proposed exit fee is based on the average depreciated value of the existing type 5 and type 6 meters. ActewAGL Distribution has calculated its proposed exit fee by taking the average of the opening and closing RAB for the year and dividing it by the forecast number of metering customers at the end of June 2015.

The proposed fee exit fee must be set at a level that allows ActewAGL Distribution to fully recover its residual asset costs. That is, the exit fee much be set at a level such that if all its customers switched to a new providers, then the sum of the exit fees collected would cover the residual meter values plus associated transfer costs.

As noted above, SCER recognised that the exit fee should allow recovery of "efficient and reasonable costs of processing the customer transfer to another Metering Coordinator".[1156] ActewAGL Distribution notes that the cost of administering customer transfer will depend on the extent of the transfer. In the case where all ActewAGL Distribution's metering customers are transferred to a newly appointed Metering Coordinator at the same time, the costs will be significantly less than in the case where customers gradually shift.

[1155] SCER 2013, *Introducing a new framework in the National Electricity Rules that provides for increased competition in metering and related services Rule change request*, October, p. 23

[1156] SCER 2013, *Introducing a new framework in the National Electricity Rules that provides for increased competition in metering and related services Rule change request*, October 2013, p. 12

ActewAGL Distribution's proposed metering transfer administration fee would apply only if customers transfer to an alternative Metering Coordinator when they install a new meter. If all a retailer's customers transfer to an alternative metering coordinator when the retailer appoints the Metering Coordinator, the transfer fee would not apply. The proposed transfer fee is based on ActewAGL Distribution's estimate of the time taken to process a customer transfer. The calculation is provided in the ancillary services model, provided as Attachment H18 to this revised regulatory proposal. ActewAGL Distribution's proposed fees for the meter transfer service are shown in Table 14.1.

Table 14.1 Proposed exit fees for meter transfer service ($2014/15)

	2015/16	*2016/17*	*2017/18*	*2018/19*
Meter exit fee (recovery of meter asset value)	$274.62	$246.92	$217.57	$186.49
Meter transfer administration fee	$30.79	$31.32	$31.79	$32.26

AER's B factor adjustment

If (contrary to ActewAGL Distribution's revised proposal and contentions) the AER maintains its draft decision on the recovery of residual meter capital costs in making its final decision, ActewAGL Distribution considers that there are problems with the AER's proposed B factor adjustment that would need to be addressed in the final decision.

Specifically, ActewAGL Distribution is concerned that the tolerance limits that form part of the AER's proposed B factor adjustment may preclude it from recovering the residual capital costs of stranded meters resulting from meter transfers occurring in the SRP following the commencement of any Competition and related services Rule change made by the AEMC.

Under the AER's proposal, the recovery via the B factor adjustment would commence only on the anticipated commencement of such a Rule change on 1 July 2017, when only two years of the regulatory period remain. At the same time, the tolerance limits, set out in Attachment 14 of the draft decision, refer to recovery *"over the remainder of the regulatory period"*, if the change is greater than 2 per cent in any year.

Under the plausible scenario that on 1 July 2017 (or whenever the Rule change commences) retailers appoint a new Metering Co-ordinator and a large proportion, or potentially all, ActewAGL Distribution's metering customers exit, ActewAGL Distribution would need to recover the residual meter costs in network tariffs over the remaining 2 years of the SRP. However, this is not likely to be permitted by the tolerance limits applicable to the B factor adjustment, which are likely to bind in this scenario.

It is unclear whether and how ActewAGL Distribution would recover its residual meter costs in the 2 years of the SRP in which the AER's proposed B factor adjustment would operate where, in each of those years the required adjustment may exceed 2 per cent of the annual revenue allowance for that year. Indeed, while the AER has not clearly defined how the B factor adjustment would be calculated, if it is to be based on actual churn (rather than forecast churn, based on retailers' stated intentions) ActewAGL Distribution may not be able to seek to recover any residual metering costs through the B factor until 2018/19, being the final regulatory year of the SRP.

If the residual values cannot be recovered in the SRP, it is uncertain whether they will be recovered at all, given that by the start of the next regulatory control period all metering will be contestable and the AER's likely treatment of metering services is uncertain.

Accordingly, in the event that the AER continues to reject ActewAGL Distribution's proposal to apply exit fees to recover residual meter costs and associated costs when customers switch provider, ActewAGL Distribution proposes the following modifications to the AER's proposed B factor adjustment. These modifications are necessary to manage the risk that ActewAGL Distribution may not be able to fully recover residual asset values and related costs of customer transfers:

- residual meter values should be recovered via network charges from the start of the 2015-19 period, rather than progressively from 1 July 2017 (as under the AER's draft decision);
- the residual value of all metering assets in ActewAGL Distribution's metering RAB should be divided by four and recovered in the B factor in the formulae for the standard control services control mechanism over the 4 years of the SRP; and,
- no tolerance limits should apply to the annual adjustment.

This modified B factor proposal has several advantages relative to the AER's draft decision in that:

- it reduces the risk that ActewAGL Distribution will not be able to fully recover residual meter asset values (which otherwise arises under the AER's proposed tolerance limits);
- it allows a smoother transition, over a 4 year period rather than a one or two year period;
- it avoids the need for two schedules of annual metering charges. Rather, there would be one set of metering charges from 1 July 2015, and these would be significantly lower as they would not need to recover the capital costs of existing meters. From 1 July 2015, ActewAGL Distribution would not treat new and replacement meters as an asset, as consumers would pay for the replacement and maintenance of meters in their annual metering charges. ActewAGL Distribution would need to forecast the number of meter replacements to be recovered in charges and may need to keep an account of meter replacement costs and revenue while metering continues to be regulated; and
- there will not be a residual metering asset base to be managed at the end of the SRP.

ActewAGL Distribution appreciates the AER's concern about potential price shocks for customers. However, tolerance limits are not required in the context of the ActewAGL Distribution distribution determination. Consumers would not experience price shocks under ActewAGL Distribution's modified B factor adjustment. Metering charges would be declining for all metering customers. Standard control services prices would still be expected to fall, but by less than in the absence of the B factor adjustment for metering costs. (They would effectively decline by 20 per cent in 2015/16 rather than 27 per cent as contemplated by the draft decision.)

Up-front capital charges for new and upgraded meters

The AER's draft decision is to require up-front charges to recover the costs of new and upgraded meters (instead of the alternative of adding the meters to the RAB and recovering the costs through annual metering charges), from 1 July 2015. This will increase the complexity of the charging schedule for retailers and customers, compared with ActewAGL Distribution's proposal for continuation of a single set of annual charges, as two sets of charges will be required. However, ActewAGL Distribution accepts that up-front charges will provide appropriate price signals for customers and also reduce the risk of stranded assets in the metering RAB.

While ActewAGL Distribution accepts that up-front charges should apply, it does not agree with the AER determined charges as shown in Table 16-16 in Appendix A to Attachment 16 to the draft decision for the following reasons,.

ActewAGL Distribution does not install type 6 meters. Therefore, the AER's proposed prices for type 6 meters are redundant. ActewAGL Distribution's charges for type 5 meters are based on its cost of meters (which the AER has accepted)[1157] adjusted to include overhead costs of 20 per cent and the income tax associated with gifted assets.[1158] In addition, ActewAGL Distribution proposes to charge for the cost of installation. The AER's charges in Table 16-16 do not appear to include installation costs. ActewAGL Distribution proposes two types of installation charges. The first is for the first meter at a premise and the second charge applies to additional meters installed at the same location during the first visit. The calculation of the proposed charges is shown in the ancillary services model, provided as Attachment H18 to this revised regulatory proposal.

ActewAGL Distribution's proposed up-front charges for new and upgrade meters are shown in Table 14.2 below.

[1157] See Table A.2-1 in the Confidential Appendix to Attachment 16 of the draft decision

[1158] The income tax effect inflates the meter price to recover the 30 per cent income tax less 8 per cent depreciation on the original cost of installing the asset.

Table 14.2 Proposed charges for new and upgrade meters ($2014/15)

Meter type	*Charge*
Install meter (excludes cost of meter)	$359.54
Install subsequent meter - same location & visit (excludes meter)	$179.77
Install / Replace Meter – Micro Renewable Energy Installation (excludes meter)	$359.54
Single phase, single element manually read interval meter	$129.22
Single phase, two element meter	$234.85
Three phase meter	$356.16

Revenue building blocks

The AER's draft decision is to accept a building block approach to setting annual charges but not accept ActewAGL's proposed capex and opex as components of that building block approach. The AER also does not accept ActewAGL Distribution's proposed opening value for the metering RAB.[1159]

For capex, the AER's draft decision allows $7.9 million ($2013/14) in net capital expenditure for annual metering charges instead of the proposed $33.5 million ($2013/14). This is a result of:

- The AER's draft decision that customers should pay for new/upgraded meter capital costs upfront and therefore does not need to be part of the capital expenditure building block of annual charges; and,
- The AER's cost assessment. Based on advice from its consultants, Marsden Jacobs, the AER does not accept ActewAGL Distribution's unit costs for type 6 meters. However the AER does accept ActewAGL Distribution's proposed unit costs for all other material inputs and for non-material (labour) inputs.[1160]

In response to the AER's capex draft decision, ActewAGL Distribution:

[1159] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p. 16-29

[1160] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p. 16-30

- Accepts the capex reduction for new and replacement meters. ActewAGL Distribution agrees that this adjustment is appropriate, given the draft decision to require ActewAGL Distribution to apply up-front charges to metering;
- Does not accept the AER's draft decision adjustments for material unit rates. The AER says that it accepts ActewAGL Distribution's proposed unit rates for type 5 meters, but replaces ActewAGL Distribution's proposed unit rates for type 6 meters, as these lie above the efficient benchmark range estimated by Marsden Jacobs. However, under the current jurisdictional requirements all new, upgrade and replacement meters must be type 5 meter (not type 6). The type 5 unit rate is therefore relevant in the context of ActewAGL Distribution's capex proposal, and the AER has accepted that proposed unit rate. Therefore ActewAGL Distribution contends that there is no basis for a reduction in the capex allowance due to adoption of the AER's unit rates.
- Updates the proposed cost escalators and the CPI. This will ensure a consistent approach across alternative control and standard control services. The update of the escalators and the CPI is also consistent with the AER's view that the most up-to-date input information should be used in the determination. The proposed cost escalators are addressed in Chapters 3 and 4 of this revised regulatory proposal.

ActewAGL Distribution's revised proposed capex is $12.7 million ($2013/14).

For opex, the AER's draft decision is to reject ActewAGL Distribution's proposed $19.4 million capex ($2013/14) and replace it with its forecast of $14.0 million ($2013/14). The reduction is a result of the AER's:

- Rejection of two of ActewAGL Distribution's proposed step changes (TNSP meter costs and visual inspection costs);
- A minor adjustment to ActewAGL Distribution's base year opex; and,
- Application of different escalators to ActewAGL Distribution's.

In response to the AER's draft decision for opex, ActewAGL Distribution**:**

- Accepts the draft decision to remove the TNSP meter step change. ActewAGL Distribution accepts that these costs should not be included in the alternative control services metering opex. The costs have been shifted to the standard control services transmission opex.
- Does not accept the draft decision to remove the costs for visual inspection of meters. As the AER notes in the draft decision, ActewAGL Distribution's Metering Asset Management Plan indicates that the visual inspection was expected to be undertaken in 2013. However the inspection program was not undertaken and it is now scheduled to be undertaken during the 2015-19 regulatory period. The inspection program is carried

out in accordance with the requirements in the NER and ActewAGL Distribution must be given a reasonable opportunity to recover these costs.

- Does not accept the AER's draft decision adjustments to the base year opex. The AER reduces the base year expenditure (by $0.1 million) on the basis that, because an efficiency benefit sharing scheme does not apply, revealed costs are not appropriate and an historical average over the past 4 years is a more appropriate base. ActewAGL Distribution does not accept this. The AER has not shown that the proposed base year opex is inefficient and therefore has no basis for replacing it with the historical average.
- Updates the proposed cost escalators (as for standard control services opex) and the CPI. This will ensure a consistent approach across alternative control and standard control services. The update of the escalators and the CPI is also consistent with the AER's view that the most up-to-date input information should be used in the determination.

ActewAGL Distribution's revised proposed opex is $15.7 million ($2013/14).

In addition to revising its proposed capex and opex building blocks, ActewAGL Distribution proposes to revise its treatment of depreciation. In the revised PTRM ActewAGL Distribution has adopted accelerated depreciation, over 9 years. Nine years was chosen as this is the 4 years of the SRP plus 5 years of the following regulatory period. The AER has noted the potential to use accelerated depreciation to address the risk of stranded assets, from the end of the 2014-19 regulatory period.[1161] ActewAGL Distribution considers that it is appropriate to adopt accelerated depreciation in the SRP, given the significant risk of stranded assets following the introduction of competition, expected in 2017. By adopting accelerated depreciation from 1 July 2015, ActewAGL Distribution will also be able to reduce the value of its exit fees, compared with what they would be with depreciation over the standard life of the asset.

ActewAGL Distribution's revised building block proposal for alternative control metering services for existing customers (who have not paid up-front for their meter) is shown in Table 14.3 below. The revised PTRM and RFM for alternative control metering services are provided at Attachments H7 and H10.

[1161] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p. 16-34

Table 14.3 Revised building block proposal for alternative control metering services

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Return on capital	4.4	4.6	4.3	3.9	3.5
Regulatory depreciation	4.5	5.4	5.9	6.5	7.2
Operating expenditure	3.0	3.2	3.3	3.5	4.3
Tax allowance	1.0	1.0	1.1	1.1	1.1
Total revenue building block (unsmoothed)	12.8	14.2	14.5	15.0	16.1
Smoothed revenue requirement	9.1	15.2	15.8	16.4	17.0
X-factor (%)	0.0%	-60.9%	0.0%	0.0%	0.0%

ActewAGL Distribution also provides modelled revenues used to calculate tariffs for new and upgrade customers (who have paid an up-front charge for their meter). These are based on the same opex and capex figures underpinning the revenues in Table 14.3. In Table 14.4, all expenditure is expensed as there is no capital assumed to be recovered. ActewAGL Distribution notes that there is no double counting of the revenues given that ActewAGL Distribution only will recover revenues from one of the tariffs (that is, a customer will only pay tariffs relating to the existing services (Table 14.3) or new or upgrade services (Table 14.4)).

Table 14.4 Revised building block proposal for alternative control metering services (new and upgrade customers)

$ million (nominal)	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Return on capital					
Regulatory depreciation					
Operating expenditure	9.3	4.8	5.0	5.2	6.1
Tax allowance					
Total revenue building block (unsmoothed)	9.3	4.8	5.0	5.2	6.1
Smoothed revenue requirement	9.1	5.0	5.2	5.4	5.6
X-factor (%)	0.0%	46.83%	0.0%	0.0%	0.0%

Annual metering charges for existing and new customers

It follows from its acceptance of the AER's draft decision concerning up-front capital charges that ActewAGL Distribution also accepts the AER's draft decision that there should be two schedules of annual charges, one for existing customers (the annual charges for whom should include capital cost recovery) and the other for new customers (who have made an upfront capital contribution and the annual charges for whom should not recover any capital cost).

As noted above, in the draft decision, the AER sets out only one schedule of annual metering charges, notwithstanding its decision that there should be two schedules of annual metering charges. ActewAGL Distribution has calculated annual metering charges on the basis that different charges are to apply for each of existing and new (and upgrade) customers. ActewAGL Distribution's proposed two schedules of annual metering charges for the subsequent regulatory period are set out in Table 14.5 and Table 14.6 below. These are determined using ActewAGL Distribution's revised building block proposal and X factors.

If the revised X factors were applied to each metering charge, metering charges would be distorted.[1162] Therefore, to calculate the metering charges for 2015/16, a weighted price cap approach was applied using the customer numbers in 2013/14. The revenue earned using current prices and the average customer numbers in 2013/14 was calculated to derive total revenue from current prices. Then the X factor was applied to this sum to determine the allowable revenue for 2015/16 metering prices. A single amount was added to (or subtracted from) all metering charges to generate the metering charges for 2015/16, ensuring that the metering revenue did not exceed the cap.

[1162] The large X factor was required to recover the accelerated depreciation. The metering charges for interval meters are higher because of the data retrieval and processing costs. These costs are unaffected by accelerated depreciation. Therefore, it would have been inappropriate to inflate the metering tariffs for interval meters by the full X factor.

Table 14.5 Proposed annual metering charges (excluding GST) – existing customers ($2014/15)

Code	*Description*	*Unit*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
MP1	**Quarterly basic metering rate**					
	Accumulation and time-of-use meters read quarterly	cents per day per NMI	22.01	22.01	22.01	22.01
MP2	**Monthly basic metering rate**					
	Accumulation and time-of-use meters read monthly	cents per day per NMI	32.00	32.00	32.00	32.00
MP3	**Time-of-use metering rate**					
	Time-of-use meters read monthly	cents per day per NMI	32.00	32.00	32.00	32.00
MP4	**Monthly manually-read interval metering rate**					
	Interval meters recording at either 15- or 30-minute intervals, read manually and processed monthly	$ per day per NMI	1.97	1.97	1.97	1.97
MP6	**Quarterly manually-read interval metering rate**					
	Interval meters recording at either 15- or 30-minute intervals, read manually and processed quarterly	cents per day per NMI	62.40	62.40	62.40	62.40

ActewAGL Distribution's proposed annual metering charges for new and upgrade customers are shown in Table 14.6.

Table 14.6 Proposed annual metering charges (excluding GST) – new and upgrade customers ($ 2014/15)

Code	Description	Unit	2015/16	2016/17	2017/18	2018/19
MP1	**Quarterly basic metering rate**					
	Accumulation and time-of-use meters read quarterly	cents per day per NMI	6.67	6.67	6.67	6.67
MP2	**Monthly basic metering rate**					
	Accumulation and time-of-use meters read monthly	cents per day per NMI	16.66	16.66	16.66	16.66
MP3	**Time-of-use metering rate**					
	Time-of-use meters read monthly	cents per day per NMI	16.66	16.66	16.66	16.66
MP4	**Monthly manually-read interval metering rate**					
	Interval meters recording at either 15- or 30-minute intervals, read manually and processed monthly	$ per day per NMI	1.81	1.81	1.81	1.81
MP6	**Quarterly manually-read interval metering rate**					
	Interval meters recording at either 15- or 30-minute intervals, read manually and processed quarterly	cents per day per NMI	47.06	47.06	47.06	47.06

14.4 Ancillary network services

14.4.1 ActewAGL Distribution's proposal

Fee based ancillary network services

ActewAGL Distribution's proposed fee based ancillary network services were set out in Table 15.10 of its regulatory proposal for the SRP.[1163] Those services relevantly included de-energisation for debt non-payment.

In its regulatory proposal for the SRP, ActewAGL Distribution:[1164]

- accepted the AER's decision, in the Stage 1 F&A Paper, that price caps should apply to fee based ancillary network services;
- used a cost build-up approach to determine the cost of providing each fee based ancillary network service, taking account of the time spent in delivering the service, the required labour types and the labour costs, and any other input costs, including materials and contractor costs;
- proposed a phased approach to full cost recovery for those ancillary network services for which there is a significant difference between prices and costs in the to avoid price shocks for customers; and
- proposed X factors for each service for each of the regulatory years of the SRP, to implement the transition to full cost recovery.

ActewAGL Distribution's proposed X factors for its fee based ancillary network services fees for each regulatory year of the SRP, were set out in Table 15.11 of its regulatory proposal for the SRP.[1165] For those ancillary network services for which costs and prices are equal in the TRP, the proposed X factor was 1.5 per cent (being the assumed annual real increase in costs over the

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[1163] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, June (resubmitted 10 July 2014), pp. 343-345

[1164] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, June (resubmitted 10 July 2014), pp. 342-348

[1165] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, June (resubmitted 10 July 2014), pp. 345-347

SRP). Where costs were greater than the initial prices in the TRP, X factors of greater than 1.5 per cent were proposed (so that costs equalled prices by the end of the SRP). Where costs were below the initial prices, the X factors were set below 1.5 per cent.

Quoted ancillary network services

In its regulatory proposal for the SRP, ActewAGL Distribution proposed:[1166]

- to set prices on a quoted basis for those ancillary network services that are not typical or standard or for which the scope of the service is specific to the particular customer's needs;
- prices for quoted services should be calculated using the formula: *Price = labour + contractor services + materials + other costs + risk margin*; and
- price caps should apply to the labour rates used in the form of control for quoted services only, rather than to all cost inputs, and compliance with the formula will be demonstrated through annual calculation of labour rates in the annual pricing proposal.

14.4.2 AER draft decision

Fee based ancillary network services

In its draft decision, the AER:[1167]

- gives effect to its decision, in the Stage 1 F&A Paper, that price caps should apply as the form of control for fee based ancillary network services;
- consistent with the proposed formulae for the control mechanism for alternative control services set out in its Stage 1 F&A Paper, specifies the formula for the control mechanism for fee based ancillary network services to be:

$$\bar{p}_i^t \geq p_i^t \qquad i=1,\ldots n \text{ and } t=1,\ldots 4,$$

$$\bar{p}_i^t = \bar{p}_i^{t-1}(1+CPI_t)(1-X_i^t)$$

Where:

[1166] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, June (resubmitted 10 July 2014), pp. 348-350

[1167] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, pp. 16-10 to 16-11

$\overline{p}_i^t$ *is the cap on the price of service i in year t.*

p_i^t *is the price of service i in year t.*

CPI_t *is the percentage increase in the consumer price index, calculated as follows*

The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the December Quarter immediately preceding the start of regulatory year t;

divided by

The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the December Quarter immediately preceding the start of regulatory year t-1;

minus one.

X_i^t *is the X-factor for service i in year t.*

$\overline{p}_i^1$ *is the cap on the price of service i in the first year of the subsequent regulatory control period. To be decided in the final decision.*

- approves ActewAGL Distribution's proposed 2015/16 fees for fee based ancillary network services (reproduced in Table 16.12 in Appendix A.1 to Attachment 16 to its draft decision[1168]);
- does not approve ActewAGL Distribution's proposed fees for fee based ancillary network services for the remaining years of the SRP because it does not approve ActewAGL Distribution's proposed annual escalation rate of 1.5 per cent, and instead applies its own labour escalation rates set out in Table 16.1 to the draft decision; and
- approves a schedule of X factors for fee based ancillary network services (set out in Table 16.13 in Appendix A.1 to Attachment 16 to its draft decision[1169]), which allow a phased transition to full cost recovery by the end of the SRP but to lower final prices (set out in Table 16.11 in Appendix A.1 to Attachment 16 to its draft decision[1170]) than those

[1168] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*: Appendix A, November, pp. 16-41 to 16-45

[1169] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*: Appendix A, November, pp. 16-46 to 16-51

[1170] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*: Appendix A, November, pp. 16-36 to 16-40 proposed by ActewAGL Distribution, given that the AER adopted annual escalation rates below 1.5 per cent.

In so doing, the AER decides on a fee for the final regulatory year of the SRP for two of ActewAGL Distribution's proposed fee based ancillary network services for which ActewAGL Distribution did not propose a fee,[1171] being:[1172]

- New underground service connection - greenfield; and
- New underground service connection - greenfield metering only.

While the AER specifies a price for the final year of the SRP for each of these additional services, however, it fails to specify any X factor for those services.[1173]

The AER also expressly accepts ActewAGL Distribution's proposed disconnection for debt non-payment service fee on the basis that this fee is reasonable.[1174]

Finally, ActewAGL Distribution observes that the AER does not, in its draft decision, purport to make any constituent decision on how compliance with the control mechanism for fee based ancillary network services is to be demonstrated.

Quoted ancillary network services

The AER sets out its draft decision on the form of control for quoted ancillary network services as follows:[1175]

[1171] ActewAGL Distribution 2014, *Regulatory Proposal 2015-19 Subsequent regulatory control period Distribution services provided by the ActewAGL Distribution electricity network in the Australian Capital Territory*, 2 June 2014 (resubmitted 10 July 2014), p. 343, Table 15.10, Codes 523 and 525

[1172] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*: Appendix A, p. 16-37, Table 16.11

[1173] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*: Appendix A, p. 16-47, Table 16.13, Codes 523 and 525

[1174] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*,, p. 16-19

[1175] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, p. 16-18. ActewAGL Distribution observes that, in purporting to reproduce its draft decision on the form of control for quoted services on p. 16-12 of Attachment 16 and on p. 59 of the Overview, the AER omits the 'risk margin' term from the form of control. ActewAGL Distribution understands the AER's draft decision to be to approve ActewAGL Distribution's proposed form of control - that is, inclusive of the 'risk margin'

We approve ActewAGL's proposed form of control for quoted services:

Price = labour + contractor services + materials + other costs + risk margin.

The AER does not approve ActewAGL Distribution’s proposed labour rates for quoted services for office support delivery and senior technical officer, on the basis that the proposed rates do not fall within the benchmark maximum recommended by its consultants, Marsden Jacobs.[1176] The AER instead adopts the rates recommended by its consultants.[1177] ActewAGL Distribution’s proposed rates for labour categories other than office support delivery and senior technical officer all fall within the benchmark recommended by the consultants and are therefore accepted by the AER. The AER sets out its approved maximum labour rates (including on-costs) for quoted ancillary network services in Table 16.3 to the draft decision.[1178]

Finally, ActewAGL Distribution observes that the AER does not, in its draft decision, purport to make any constituent decision on how compliance with the control mechanism for quoted ancillary network services is to be demonstrated.

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term - and the omission of this term in the form of control set out on p. 16-12 of Attachment 16 and on p. 59 of the Overview to be the result of a transcription error. This is because, first, the AER expressly states (on p. 16-18 of Attachment 16) that its draft decision is to 'approve ActewAGL's proposed form of control' and, secondly, the AER's reasons for decision on the control mechanism for quoted services (at p. 16-18) do not make any mention of the 'risk margin' term. In the event that ActewAGL Distribution's understanding of the AER's draft decision is incorrect, it observes therefore that the AER's obligation under section 16(1)(b) of the NEL and its common law obligation to accord procedural fairness would require it to inform ActewAGL Distribution of this, together with the AER's reasons for taking issue with the 'risk margin' term, and provide ActewAGL Distribution with a reasonable opportunity to make submissions on this matter before the distribution determination for the SRP is made.

[1176] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p.16-16

[1177] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p. 16-18

[1178] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 16*, November, p. 16-12; see also Appendix A, section A.1.2, Table 16.14, p. 16-52

14.4.3 ActewAGL Distribution's response and revised proposal

Fee based ancillary network services

Consistent with the AER's decision that the capital costs of new meters should be recovered up-front with effect from 1 July 2015 and ActewAGL Distribution's acceptance of that decision in this revised regulatory proposal, the revised ancillary network services fees for affected ancillary network services proposed include those costs. The following services have been added to the list of ancillary services:

- Install meter (excludes cost of meter)
- Install subsequent meter - same location & visit (excludes meter)
- Install / Replace Meter – Micro Renewable Energy Installation (excludes meter)
- Single phase, single element manually read interval meter
- Single phase, two element meter
- Three phase meter
- Meter exit fee (recovery of meter asset value)
- Metering transfer admin fee (transfer to another metering provider)

However, ActewAGL Distribution does not accept the following elements of the AER's draft decision:

- the AER's draft decision on labour escalation rates to apply to fees for fee based alternative control services for the SRP. ActewAGL Distribution's reasons for not accepting the AER's labour escalation rates are set out in Chapter 3 of this revised regulatory proposal; or
- the AER's draft decision to apply a fee for ActewAGL Distribution's new underground service connection - greenfield and greenfield metering only - services. The application of fees for these services would be inconsistent with ActewAGL Distribution's Connection Policy, as approved by the AER in Attachment 18 to the Draft Decision.

Therefore, ActewAGL Distribution proposes to remove the following ancillary charges:

- New Underground Service Connection – Greenfield Cable Only
- New Underground Service Connection – Greenfield Metering Only

In response to the AER's Draft Decision, ActewAGL Distribution proposes the following revisions to its regulatory proposal for the SRP that affect the X factors for fee based ancillary network services fees for the SRP:

- full cost recovery for all fee based ancillary network services from 2015/16, instead of a gradual transition to full cost recovery over the course of the SRP, if the AER maintains its draft decision to significantly reduce allowed revenues from standard control services in making its final decision. The significantly lower allowed revenues from standard control services would mean that ActewAGL Distribution would not be able to subsidise the provision of fee based ancillary network services during the SRP, so as to allow a transition to full cost recovery to manage price shocks; and
- adoption of ActewAGL Distribution's revised proposed labour escalation rates, rather than the 1.5 per cent escalation rate determined by the AER in its Draft Decision, for the reasons advanced in respect of these revised proposed labour escalation rates in Chapter 3 of this revised regulatory proposal.

ActewAGL Distribution's revised proposed charges for fee based ancillary network services are shown in Table 14.7 below and the revised proposed X factors are shown in Table 14.8 below.

Table 14.7 Proposed charges for fee based ancillary services

Code	Service	Current Prices 2014/15	2015/16 Prices ($'2014/15)
Premise Re-energisation – Existing Network Connection			
501	Re-energise premise – Business Hours	$56.14	$64.47
502	Re-energise premise – After Hours	$120.73	$81.71
Premise De-energisation – Existing Network Connection			
503	De-energise premise – Business Hours	$49.59	$64.47
505	De-energise premise for debt non-payment	$93.55	$128.93
Meter installation			
507	Install meter (excludes cost of meter)	$66.55	$359.54
508	Install subsequent meter - same location & visit (excludes meter)		$179.77
509	Install / Replace Meter – Micro Renewable Energy Installation (excludes meter)	$66.55	$359.54
511	Single phase, single element manually read interval meter		$129.22
512	Single phase, two element meter		$234.85
513	Three phase meter		$356.16
Meter Investigations			
504	Meter Test (Whole Current) – Business Hours	$69.23	$257.86
510	Meter Test (CT/VT) – Business Hours	$350.00	$306.79
Special metering services			
506	Special Meter Read	$35.55	$37.98

514	Meter exit fee (recovery of meter asset value)		$274.62
515	Metering transfer admin fee (transfer to another metering provider)		$30.79
Temporary Network Connections			
520	Temporary Builders Supply – Overhead (Business Hours) (excludes meter cost)	$398.64	$579.43
522	Temporary Builders Supply – Underground (Business Hours) (excludes meter costs)	$703.64	$1,264.93
New Network Connections			
523	New Underground Service Connection – Greenfield		$0.00
526	New Overhead Service Connection – Brownfield (Business Hours)	$288.18	$761.01
527	New Underground Service Connection – Brownfield from Front	$691.82	$1,264.93
528	New Underground Service Connection – Brownfield from Rear	$691.82	$1,264.93
Network Connection Alterations and Additions			
541	Overhead Service Relocation – Single Visit (Business Hours)	$288.18	$726.35
542	Overhead Service Relocation – Two Visits (Business Hours)	$576.36	$1,452.70
543	Overhead Service Upgrade – Service Cable Replacement Not Required	$371.45	$726.35
544	Overhead Service Upgrade – Service Cable Replacement Required	$691.82	$761.01
545	Underground Service Upgrade – Service Cable Replacement Not Required	$371.45	$1,230.27
546	Underground Service Upgrade – Service Cable Replacement Required	$691.82	$1,264.93
547	Underground Service Relocation – Single Visit (Business Hours)	$691.82	$1,264.93
548	Install surface mounted point of entry (POE) box	$456.00	$584.99
Temporary De-energisation			
560	Temporary de-energisation – LV (Business Hours)	$462.27	$386.80
561	Temporary de-energisation – HV (Business Hours)	$462.27	$386.80
Supply Abolishment / Removal			
562	Supply Abolishment / Removal – Overhead (Business Hours)	$288.18	$544.76
563	Supply Abolishment / Removal - Underground (Business Hours)	$288.18	$984.21
Miscellaneous Customer Initiated Services			
564	Install & Remove Tiger Tails – Per Installation (Business Hours)	$1,085.00	$1,279.28
565	Install & Remove Tiger Tails - Per Span (Business Hours)	$560.00	$644.00
566	Install & Remove Warning Flags – Per Installation (Business Hours)	$745.00	$1,089.53

567	Install & Remove Warning Flags - Per Span (Business Hours)	$480.00	$552.00
Embedded Generation - Operational & Maintenance Fees			
568	Small Embedded Generation OPEX Fees - Connection Assets	2%	2%
569	Small Embedded Generation OPEX Fees - Shared Network Asset	2%	2%
Connection Enquiry Processing - PV Installations			
570	PV Connection Enquiry – LV Class 1 (<= 10kW Single Phase / 30kW Three Phase)	$0.00	$0.00
571	PV Connection Enquiry – LV Class 2 to 5 (> 30kW <= 1500kW Three Phase	$514.55	$529.62
572	PV Connection Enquiry – HV	$1,029.09	$1,059.23
573	Provision of information for Network technical study for large scale installations	$11,580.00	$10,592.32
Network Design & Investigation / Analysis Services - PV Installations			
574	Design & Investigation - LV Connection Class 1 PV (<= 10kW Single Phase / 30kW Three Phase)	$0.00	$0.00
575	Design & Investigation - LV Connection Class 2 PV (> 30kW and <= 60kW Three Phase)	$3,705.45	$3,530.77
576	Design & Investigation - LV Connection Class 3 PV (> 60 kW and <= 120kW Three Phase)	$4,837.27	$5,296.16
577	Design & Investigation - LV Connection Class 4 PV (> 120 kW and <= 200kW Three Phase)	$7,925.45	$7,061.55
578	Design & Investigation - LV Connection Class 5 PV (> 200kW and <= 1500kW Three Phase) – ActewAGL Network Study	$10,732.73	$10,592.32
579	Design & Investigation - HV Connection Class 5 PV (> 200kW and <= 1500kW Three Phase) – Customer Network Study	$11,560.00	$13,240.40
Residential Estate Subdivision Services*			
580	URD Subdivision Electricity Distribution Network Reticulation - Multi-Unit Blocks	$0.00	$0.00
581	URD Subdivision Electricity Distribution Network Reticulation - Blocks <= 650 m2	$600.00	$600.00
582	URD Subdivision Electricity Distribution Network Reticulation - Blocks 650 - 1100m2 with average linear frontage of 22-25 meters	$1,100.00	$1,100.00
Upstream Augmentation**			
585	HV Feeder	$34.20	$34.64
586	Distribution substation	$19.82	$20.08
Rescheduled Site Visits			
590	**Rescheduled Site Visit – One Person**	$125.00	$128.93
591	**Rescheduled Site Visit – Service Team**	$375.00	$544.76

Trenching charges			
592	Trenching - first 2 meters	$494.50	$494.50
593	Trenching - subsequent meters	$115.00	$115.00
Boring charges			
594	Under footpath	$897.00	$897.00
595	Under driveway	$1,069.50	$1,069.50

Table 14.8 Proposed X factors for fee based ancillary services

Code	Service	2016/17	2017/18	2018/19
	Premise Re-energisation – Existing Network Connection			
501	Re-energise premise – Business Hours	1.70%	1.50%	1.50%
502	Re-energise premise – After Hours	1.70%	1.50%	1.50%
Premise De-energisation – Existing Network Connection				
503	De-energise premise – Business Hours	1.70%	1.50%	1.50%
505	De-energise premise for debt non-payment	1.70%	1.50%	1.50%
Meter installation				
507	Install meter (excludes cost of meter)	1.70%	1.50%	1.50%
508	Install subsequent meter - same location & visit (excludes meter)	1.70%	1.50%	1.50%
509	Install / Replace Meter – Micro Renewable Energy Installation (excludes meter)	1.70%	1.50%	1.50%
511	Single phase, single element manually read interval meter	0.00%	0.00%	0.00%
512	Single phase, two element meter	0.00%	0.00%	0.00%
513	Three phase meter	0.00%	0.00%	0.00%
Meter Investigations				
504	Meter Test (Whole Current) – Business Hours	1.70%	1.50%	1.50%
510	Meter Test (CT/VT) – Business Hours	1.70%	1.50%	1.50%
Special metering services				
506	Special Meter Read	1.70%	1.50%	1.50%
514	Meter exit fee (recovery of meter asset value)	-10.09%	-11.89%	-14.29%
515	Metering transfer admin fee (transfer to another metering provider)	1.70%	1.50%	1.50%
Temporary Network Connections				
520	Temporary Builders Supply – Overhead (Business Hours) (excludes meter cost)	1.70%	1.50%	1.50%

522	Temporary Builders Supply – Underground (Business Hours) (excludes meter costs)	1.70%	1.50%	1.50%
New Network Connections				
523	New Underground Service Connection – Greenfield			
526	New Overhead Service Connection – Brownfield (Business Hours)	1.70%	1.50%	1.50%
527	New Underground Service Connection – Brownfield from Front	1.70%	1.50%	1.50%
528	New Underground Service Connection – Brownfield from Rear	1.70%	1.50%	1.50%
Network Connection Alterations and Additions				
541	Overhead Service Relocation – Single Visit (Business Hours)	1.70%	1.50%	1.50%
542	Overhead Service Relocation – Two Visits (Business Hours)	1.70%	1.50%	1.50%
543	Overhead Service Upgrade – Service Cable Replacement Not Required	1.70%	1.50%	1.50%
544	Overhead Service Upgrade – Service Cable Replacement Required	1.70%	1.50%	1.50%
545	Underground Service Upgrade – Service Cable Replacement Not Required	1.70%	1.50%	1.50%
546	Underground Service Upgrade – Service Cable Replacement Required	1.70%	1.50%	1.50%
547	Underground Service Relocation – Single Visit (Business Hours)	1.70%	1.50%	1.50%
548	Install surface mounted point of entry (POE) box	1.70%	1.50%	1.50%
Temporary De-energisation				
560	Temporary de-energisation – LV (Business Hours)	1.70%	1.50%	1.50%
561	Temporary de-energisation – HV (Business Hours)	1.70%	1.50%	1.50%
Supply Abolishment / Removal				
562	Supply Abolishment / Removal – Overhead (Business Hours)	1.70%	1.50%	1.50%
563	Supply Abolishment / Removal - Underground (Business Hours)	1.70%	1.50%	1.50%
Miscellaneous Customer Initiated Services				
564	Install & Remove Tiger Tails – Per Installation (Business Hours)	1.70%	1.50%	1.50%
565	Install & Remove Tiger Tails - Per Span (Business Hours)	1.70%	1.50%	1.50%
566	Install & Remove Warning Flags – Per Installation (Business Hours)	1.70%	1.50%	1.50%
567	Install & Remove Warning Flags - Per Span (Business Hours)	1.70%	1.50%	1.50%

Embedded Generation - Operational & Maintenance Fees				
568	Small Embedded Generation OPEX Fees - Connection Assets			
569	Small Embedded Generation OPEX Fees - Shared Network Asset			
Connection Enquiry Processing - PV Installations				
570	PV Connection Enquiry – LV Class 1 (<= 10kW Single Phase / 30kW Three Phase)			
571	PV Connection Enquiry – LV Class 2 to 5 (> 30kW <= 1500kW Three Phase	1.70%	1.50%	1.50%
572	PV Connection Enquiry – HV	1.70%	1.50%	1.50%
573	Provision of information for Network technical study for large scale installations	1.70%	1.50%	1.50%
Network Design & Investigation / Analysis Services - PV Installations				
574	Design & Investigation - LV Connection Class 1 PV (<= 10kW Single Phase / 30kW Three Phase)			
575	Design & Investigation - LV Connection Class 2 PV (> 30kW and <= 60kW Three Phase)	1.70%	1.50%	1.50%
576	Design & Investigation - LV Connection Class 3 PV (> 60 kW and <= 120kW Three Phase)	1.70%	1.50%	1.50%
577	Design & Investigation - LV Connection Class 4 PV (> 120 kW and <= 200kW Three Phase)	1.70%	1.50%	1.50%
578	Design & Investigation - LV Connection Class 5 PV (> 200kW and <= 1500kW Three Phase) – ActewAGL Network Study	1.70%	1.50%	1.50%
579	Design & Investigation - HV Connection Class 5 PV (> 200kW and <= 1500kW Three Phase) – Customer Network Study	1.70%	1.50%	1.50%
Residential Estate Subdivision Services*				
580	URD Subdivision Electricity Distribution Network Reticulation - Multi-Unit Blocks			
581	URD Subdivision Electricity Distribution Network Reticulation - Blocks <= 650 m^2	1.70%	1.50%	1.50%
582	URD Subdivision Electricity Distribution Network Reticulation - Blocks 650 - 1100m^2 with average linear frontage of 22-25 meters	1.70%	1.50%	1.50%
Upstream Augmentation**				
585	HV Feeder	1.70%	1.50%	1.50%
586	Distribution substation	1.70%	1.50%	1.50%
Rescheduled Site Visits				
590	**Rescheduled Site Visit – One Person**	1.70%	1.50%	1.50%
591	**Rescheduled Site Visit – Service Team**	1.70%	1.50%	1.50%

Trenching charges				
592	Trenching - first 2 meters	1.70%	1.50%	1.50%
593	Trenching - subsequent meters	1.70%	1.50%	1.50%
Boring charges				
594	Under footpath	1.70%	1.50%	1.50%
595	Under driveway	1.70%	1.50%	1.50%

Quoted ancillary network services

ActewAGL Distribution is content with the AER's approval of its proposed form of control for quoted ancillary network services.

However ActewAGL Distribution does not accept the AER's draft decision to not approve ActewAGL Distribution's proposed labour rates for quoted services for office support delivery and senior technical officer. The AER provides limited explanation of the basis for its draft decision. In the confidential attachment to Attachment 16 the AER refers to "normalised" rates calculated by its consultants Marsden Jacobs,[1179] but the methodology is not explained.

ActewAGL Distribution maintains its position that its proposed labour rates for quoted ancillary services are efficient. The labour rates have been updated using ActewAGL Distribution's revised labour cost escalators (as discussed in Chapter 3). ActewAGL Distribution's revised proposed labour rates are shown in Table 14.9.

Table 14.9 Proposed labour rates for fee based and quoted services ($2014/15)

Classification	*2014/15*	*2015/16*	*2016/17*	*2017/18*	*2018/19*
Electrical Worker	85.11	86.24	87.73	89.05	90.36
Electrical Worker—Labourer	69.52	70.44	71.65	72.74	73.80
Electrical Apprentice	63.88	64.73	65.85	66.84	67.82
Office Support Service Delivery	81.31	82.39	83.81	85.08	86.32
Project Officer Design Section	100.22	101.56	103.31	104.87	106.41
Senior Technical Officer/ Engineer Design Section	137.72	139.56	141.96	144.11	146.22

Rates do not include overheads or margins. Overheads are allocated in accordance with ActewAGL Distribution's approved CAM.

[1179] AER 2014, *CONFIDENTIAL APPENDIX—Attachment 16—Alternative control services—ActewAGL*, p. 7

15 Negotiating framework and negotiated distribution service criteria

15.1 Introduction

In this Chapter 15 ActewAGL Distribution provides its response to the AER's draft decision on the negotiating framework and the Negotiated Distribution Services Criteria (NDSC).

15.2 The relevant legal and regulatory framework for negotiated distribution services

Part D of Chapter 6 of the Rules contains the regulatory requirements for negotiated distribution services. Clause 6.7.2 requires DNSPs to comply with:

- the provider's negotiating framework; and
- the provider's Negotiated Distribution Service Criteria (NDSC),

when the provider is negotiating the terms and conditions of access to negotiated distribution services.

Clause 6.7.5(a) requires the provider to prepare a document (the negotiating framework) setting out the procedure to be followed during negotiations between that provider and any person (the Service Applicant or applicant) who wishes to receive a negotiated distribution service from the provider, as to the terms and conditions of access for the provision of the service. The regulatory proposal must include the proposed negotiating framework, "for those services classified as negotiated distribution services" (Clause 6.8.2(c)(5)).

Under Clause 11.56.3(a)(9), ActewAGL Distribution's 2009-14 negotiating framework continued to apply for the transitional regulatory period. In the Placeholder Determination for the 2014/15 regulatory year the AER determined that the NDSC for ActewAGL Distribution for the transitional regulatory control period "are the negotiated distribution service criteria that were specified as part of the distribution determination for the current regulatory control period for ActewAGL".[1180]

Clauses 6.12.1(15) and (16) require the AER to include in its determination for the subsequent regulatory period decisions on the negotiating framework and the NDSC to apply for the subsequent regulatory period, 1 July 2015 to 30 June 2019.

15.3 ActewAGL Distribution's regulatory proposal and submissions

ActewAGL Distribution did not propose a negotiated framework as part of its regulatory proposal. ActewAGL Distribution explained that it understood that the Rules did not require it to submit a proposed negotiating framework, given that the AER has not classified any of its services as negotiated services, but a proposal could be submitted if requested by the AER. In response to an email request from the AER, ActewAGL Distribution submitted a proposed negotiating framework to the AER on 16 October 2014.

Clause 6.9.3 of the NER requires the AER to publish its proposed NDSC, together with an invitation for written submissions, in conjunction with the publication of ActewAGL's regulatory proposal. The AER published its proposed NDSC on 23 September 2014.

ActewAGL Distribution submitted a response to the AER on 23 October 2014.[1181] ActewAGL Distribution indicated that it considered that the AER's proposed NDSC is appropriate and consistent with the requirements in the NER. In terms of giving effect to the principles, ActewAGL Distribution suggested that the AER consider clarifying the meaning of the term "fair and reasonable" in criterion 2 by adding the words "the price for a negotiated distribution service is to be treated as being fair and reasonable if it complies with criteria 5 to 11". This would be consistent with clause 6.7.1(9) of the NER.

15.4 AER draft decision

In the draft decision the AER:

- approves ActewAGL Distribution's proposed negotiating framework; and,

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[1180] AER 2014, *ActewAGL, Placeholder determination for the transitional regulatory control period 2014/15*, April, p 4

[1181] The AER says in the draft decision that no submissions were received. However ActewAGL Distribution did submit a response, which was acknowledged by email from the AER on 23 October 2014.

- adopts the NDSC as published by the AER in September 2014.[1182]

15.5 ActewAGL Distribution's response

ActewAGL Distribution accepts the AER's draft decision on the negotiating framework. ActewAGL Distribution accepts the draft decision on the NDSC, subject to the AER considering the comments made by ActewAGL Distribution in its submission of 16 October 2014.

[1182] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 17,* November, p. 17-7

16 Transmission pricing methodology

16.1 Introduction

In this Chapter 16 ActewAGL Distribution responds to the AER's draft decision on the transmission pricing methodology. The revised transmission pricing methodology is provided as Attachment G1 to this revised regulatory proposal.

16.2 The relevant legal and regulatory framework for the transmission pricing methodology

In Stage 1 F&A paper, the AER determined under clause 6.25(b) of the Rules that Part J of Chapter 6A (transmission pricing) of the Rules will apply to relevant standard control services provided by ActewAGL's dual function assets in the subsequent regulatory period. Under clause 6.26(c) of the Rules, ActewAGL Distribution was therefore required to submit a proposed transmission pricing methodology to the AER as part of its regulatory proposal.

Clause 6.12.1(17A) requires the AER to include in its determination for the subsequent regulatory period a decision on the approval of the proposed pricing methodology for transmission standard control services.

16.3 ActewAGL Distribution's proposal

ActewAGL Distribution submitted its proposed transmission pricing methodology for the 2014-19 regulatory period to the AER in June 2014, as Attachment D15 to its regulatory proposal.

TransGrid is the *Co-ordinating Network Service Provide* for New South Wales and the ACT. TransGrid carries out the following elements of the transmission pricing methodology on behalf of ActewAGL Distribution:

- Any adjustments required to be made to the locational component of the *ASRR* as required in the Rules.
- Any adjustments required to be made to the pre-adjusted non-locational component of the *ASRR* as required in the Rules.
- Allocation of the locational component of *prescribed TUoS services* to transmission *connection point*s.
- Establishing the structure and price for common service, general, and locational charges at each of ActewAGL Distribution's transmission *connection point*s.

ActewAGL Distribution's transmission pricing methodology therefore adopts elements of TransGrid's methodology, which must also be approved by the AER.

16.4 The AER's draft decision

In the draft decision the AER:

- Accepts that ActewAGL Distribution's proposed pricing methodology accords with the requirements of the NER pricing principles;[1183] and
- Accepts that the proposed pricing methodology complies with the information requirements of the pricing methodology guidelines.[1184]

However the AER also says:[1185]

> *Some sections of ActewAGL's proposal include aspects of the pricing methodology that TransGrid proposed for its 2015–18 regulatory control period. Our draft decision for TransGrid is not to accept its pricing methodology. It follows that we do not accept ActewAGL's methodology for the same reasons. We expect that ActewAGL will engage with TransGrid about the changes both should make before submitting a revised pricing methodology.*

16.5 ActewAGL Distribution's revised proposal

Following consultation with TransGrid, ActewAGL Distribution has revised its proposed transmission pricing methodology to ensure that it is consistent with TransGrid's revised transmission pricing proposal. ActewAGL Distribution's methodology has been modified by removing the pricing methodology that the AER has not approved and advising that the methodology to be used will be TransGrid's approved allocation process for TUoS services.

ActewAGL Distribution's revised proposed transmission pricing methodology is provided at Attachment G1 to this revised regulatory proposal.

[1183] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 19*, p. 19-9

[1184] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 19*, p. 19-11

[1185] AER 2014, *Draft Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 19,* p. 19-7

List of tables

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List of attachments

The following is a list of attachments referred to in the document and which form part of ActewAGL Distribution's revised regulatory proposal.

Reference	*Title*	*Confidential*
A – Compliance		
A1	Confidentiality claim	
B – The NEO preferable decision		
B1	NERA, 2014, *Economic Interpretation of Clauses 6.5.6 and 6.5.7 of the National Electricity Rules,* Supplementary Report for Ausgrid.	No
B2	Expert Report: Greg Houston, 2014, *Evaluation of Economic Regulation Authority's Draft Decision against the National Gas Objective*, ATCO Gas Australia's Response to the ERA's Draft Decision on required amendments to the Access Arrangements for the Mid-West and South-West Gas Distribution Systems.	No
B3	Expert Report: Geff Swier, 2014, *Economic considerations for the interpretation of te National Gas Objective*, prepared for Jemena Gas Networks (NSW).	No
B4	Economic Insights 2011, *Regulation of Suppliers of Gas Pipeline Services – Gas Sector Productivity*, February, p. 33	No
B5	John Kotter, *Leading Change – Why Transformation Efforts Fail*, Harvard Business Review, 1995 (republished in Best of HBR, January 2007)	Copyright not held by ActewAGL Distribution
B6	McKinsey & Company, *Insights into Organisation – How do I Transform my Organization's Performance*, June 2011	Copyright not held by ActewAGL Distribution
B7	Bain & Company, *Company Transformation – More a Science than an Art*, Undated	Copyright not held by ActewAGL Distribution
B8	AECOM, 2015, *The Impact of the AER's Draft Decision on ActewAGL's Service and Safety Performance*, January	Yes
C Operating expenditure		
C1	Expert Report - HoustonKemp, 2015, *Opex and the efficiency*	No

	benefit sharing scheme, January	
C2	Expert Report - Advisian, 2015, *Opex cost drivers: ActewAGL Distribution Electricity (ACT),* January	No
C3	Expert Report - CEPA, 2015, *Benchmarking and setting efficiency targets for the Australian DNSPs: ActewAGL Distribution,* January	No
C4	Expert Report - Huegin, 2015, *Huegin's response to Draft Determination on behalf of NSW and ActewAGL, Technical response to the application of benchmarking by the AER,* January	No
C5	AEMC, 2012, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012,* November	No
C6	AEMC, 2006, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, November	No
C7	Williams SC, N. and Higgins, R., 2006, *Memorandum of Advice In the matter of the draft National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006*, October	No
C8	AER, 2013, *Expenditure Forecast Assessment Guideline*, November	No
C9	AER, 2013, *AER Explanatory Statement: Expenditure Forecast Assessment Guideline*, November	No
C10	ACCC/AER, 2012, *Benchmarking Opex and Capex in Energy Networks Working Paper no. 6,* May	No
C11	ActewAGL Distribution's response to the AER's detailed review of labour and vegetation management	Yes
C12	Benchmarking background and key dates in the AER's adoption of its preferred model	No
C13	ActewAGL Distribution, 2013, *Response to Expenditure forecast assessment guidelines issues paper*, March	No
C14	ActewAGL Distribution 2012, *Response to Electricity Network Regulatory Frameworks Draft Report,* November	No
C15	AEMC, 2011, *Final Report: Review into the use of total factor productivity for the determination of prices and revenues,* June	No

C16	Littlechild, S., 2012, *Advice to the AEMC on Rule Changes*, February	No
C17	Australian Government Productivity Commission, 2013, *Electricity Network Regulatory Frameworks: Productivity Commission Inquiry Report Volume 1*, April	No
C18	ACCC/AER Regulatory Development Branch, 2013, *Economic Benchmarking Model: Technical Report*	No
C19	WIK-Consult, 2011, *Cost Benchmarking in Energy Regulation in European Countries*, December	No
C20	AER/ACCC, 2012, *Regulatory Practices in Other Countries: Benchmarking opex and capex in energy networks*, May	No
C21	AER, 2012, *AER submission to the Productivity Commission Inquiry to Electricity Network Regulation,* April	No
C22	AER, 2008, *Electricity distribution network service providers Efficiency benefit sharing scheme: Final decision*, June,	No
C23	AER, 2013, *Economic Benchmarking RIN For distribution network services providers – Instructions and Definitions*, November	No
C24	AER, 2013, *Expenditure Forecast Assessment Guidelines, Category analysis – Overheads and accounting issues (workshop)*, May	No
C25	Economic Insights, 2014, *Productivity Analysis of Electricity Distribution (Commerce Commission Workshop)*, May	No
C26	Ontario Distribution Sector Review Panel, 2012, *Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First*, December	No
C27	Economic Insights, 2009, *Energy Network Total Factor Productivity Sensitivity Analysis*, June	No
C28	Economic Insights, 2009, *Assessment of Data Currently Available to Support TFP–based Network Regulation*, June	No
C29	ActewAGL Distribution, 2012, *Response to Productivity Commission Electricity Network Regulation Issues Paper*, April	No
C30	Shuttleworth, G., 2005, *Benchmarking of electricity networks: Practical problems with its use for regulation*, September	Copyright not held by ActewAGL Distribution
C31	Economic Insights, 2010, *The Productivity Performance of*	No

	Envestra's South Australian and Queensland Gas Distribution systems, September	
C32	Coelli, T., Perelman, S. and Romano, E., 1999, *Accounting for Environmental Influences in Stochastic Frontier Models: With Application to International Airlines,* Journal of Productivity Analysis, vol. 11	Copyright not held by ActewAGL Distribution
C33	Lowry, M.N., Getachew, L. and Hovde, D., 2005, *Econometric Benchmarking of Cost Performance: The Case of U.S. Power Distributors*, The Energy Journal, vol. 26, no. 3	Copyright not held by ActewAGL Distribution
C34	Lowry, M.N. and Getachew, L., 2009, *Statistical benchmarking in utility regulation: Role, standards and methods*, Energy Policy, vol. 37	Copyright not held by ActewAGL Distribution
C35	Meyrick and Associates, 2003, *Regulation of Electricity Lines Businesses Resetting the Price Path Threshold – Comparative Option*, September	No
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C71	Australian Government Treasury, *Treasury Workplace Agreement 2011 – 2014*	No
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H5	RFM Distribution	No
H6	RFM Transmission	No
H7	RFM Metering	No
H8	PTRM Distribution	No
H9	PTRM Transmission	No
H10	PTRM Metering	No
H11	PTRM Metering – no capital base	No
H12	Equity raising costs calculation – Distribution	No
H13	Equity raising costs calculation – Transmission	No
H14	Allocation of RAB between transmission and distribution	No
H15	EBSS carryover calculation	No
H16	STPIS performance targets and incentive rates	No
H17	Consumption forecast (13 parts)	No
H18	Ancillary Services Costing Workbook Including PV Revised Proposal	Yes
H19	ABS data	No