Revised Regulatory Proposal and Preliminary Submission

1 July 2014 – 30 June 2019

20 January 2015

Ausgrid

Contents

Summary

This revised regulatory proposal sets out the revisions that Ausgrid has made to its regulatory proposal in light of the Australian Energy Regulator's (AER) draft determination for Ausgrid for the period 1 July 2014 to 30 June 2019. Improvements in capital and operating efficiencies have been incorporated, while operating and maintaining the network safely and reliably and long term interests of consumers.

Since the AER's determination for the 2009-14 period, Ausgrid has proactively and continuously improved the efficiency of its capital and operating programs to deliver savings for customers. Our efficiency gains for the five years to June 2014 were boosted in July 2012 by the implementation of the NSW Network Reform program, which prioritised the progressive improvement in employee and public safety, network reliability and customer affordability aligning with the long term objectives of consumers.

Improvements in capital and operating efficiencies of $2.1 billion already delivered by Ausgrid during the 2009-14 regulatory period are progressively reducing the burden on families and businesses through real reductions in electricity network charges and these benefits will continue to flow into the future.

This revised regulatory proposal ("revised proposal"), in response to the AER's draft determination, incorporates further improvements for the five years to June 2019. Our priorities continue to align with the long term interests of consumers to achieve improvements in capital and operating programs while maintaining a safe and reliable network consistent with the National Electricity Law (NEL) National Electricity Objective (NEO), National Electricity Rules (NER or rules) and other legislation including *the Work Health and Safety Act, the Fair Work Act, Corporations Act (Cth), the NSW State Owned Corporations Act* and NSW Electricity Regulations.

Our revised proposal promotes the NEO for the reasons set out in this summary and promotes the NEO to a greater degree than the AER's draft determination for the reasons set out in the section below titled *Critique of AER's draft determination*.

Highlights of our revised proposal

The highlights of this revised proposal are:

- A network that is designed to safely deliver the NSW Government's mandated customer reliability levels, including average customer supply availability of 99.98% per annum for urban customers.
- Real reductions in forecast average distribution network charges for customers of 0.6% by the end of the period, which result in price levels that are sustainable and also avoid future price shocks.
- Forecast capital and operating programs for the 2014-19 period that are $4.9 billion (55%) and $12.2 million (0.41%)[1] less, respectively, than the AER-approved amounts for capital and operating programs in the 2009-14 period.
- Forecast labour productivity improvements of 26.6% by the end of the regulatory period.
- The adoption of Light Detection and Ranging (LIDAR) technology in bushfire-prone areas has substantially improved the detection of vegetation encroachment and network defects that must be addressed to mitigate public safety and bushfire risks.
- We propose sufficient revenue to facilitate a financially sustainable business.

A pathway to improved capital and operating efficiency

Ausgrid and the AER share a common objective for a safe, reliable and efficient electricity distribution network in the long term interest of customers. Degraded safety performance, deteriorating network reliability and unsustainable network funding are not in the long-term interest of consumers and are in conflict with the NEO.

Ausgrid and the AER also share an objective to continue to improve the capital and operating efficiency of our electricity distribution network. While that journey is well underway, further improvement is required in the interests of NSW families and businesses.

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[1] These figures are inclusive of type 5-6 metering, ancillary network services and emergency recoverable works to ensure comparability. They are also stated in $2013/14.

This revised proposal submitted by Ausgrid provides a pathway for a realistic, progressive and sustainable improvement in capital and operating efficiency while maintaining a safe and reliable network and a return commensurate with regulatory and commercial risk incorporated into the NEL.

The significant elements of this revised proposal are outlined below.

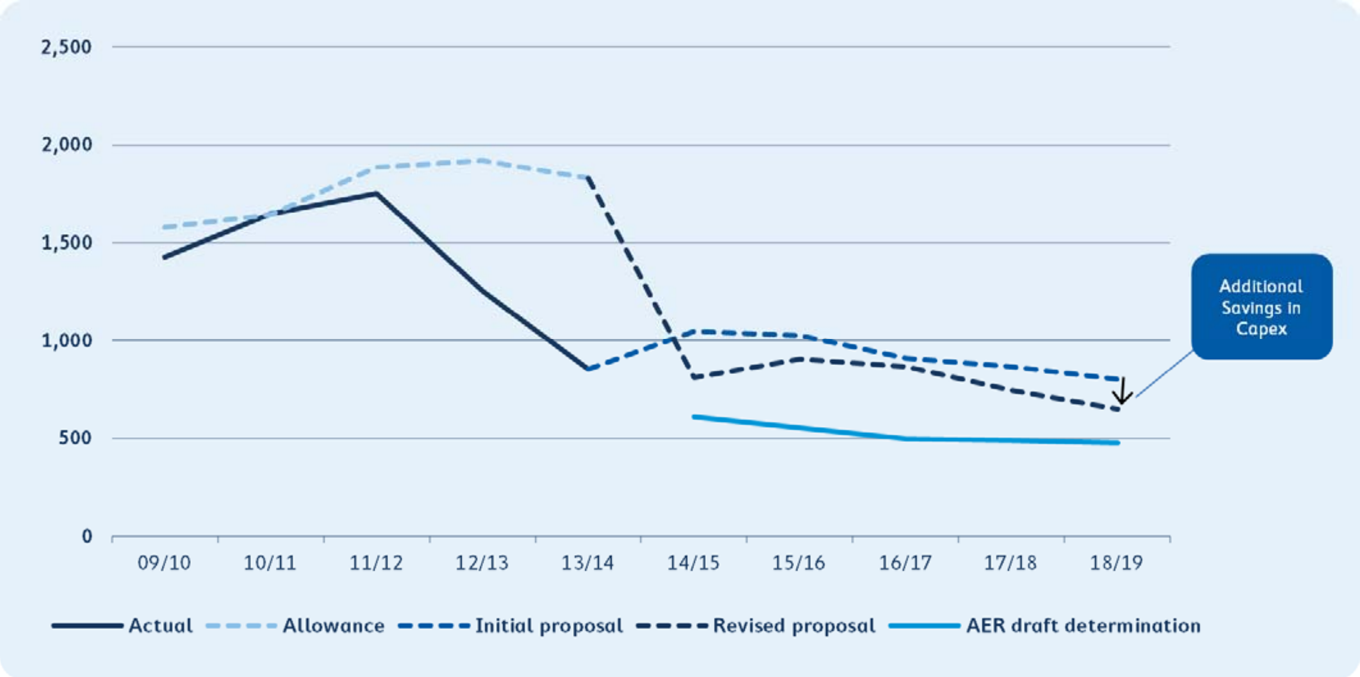
Capital Expenditure (Chapter 5)

Ausgrid's revised capital program reflects the following elements:

- A forecast capital expenditure that is 55% lower than the amount approved by the AER for 2009-14.[2]
- A forecast capital expenditure for 2014-15, which is within the amount approved by the AER for the transitional year.
- A revised capital program for the subsequent four year regulatory period which incorporates a number of aspects of the AER's draft determination and Ausgrid's revised and risk assessed capital program.
- An expenditure program that incorporates continued progressive cost reductions over the next four years through changes to program scope, more efficient project design, improved labour utilisation and reduced unit costs. Together these deliver a program that is 15% lower than our initial regulatory proposal ("initial proposal").

Figure 1 below sets out the capital expenditure in Ausgrid's initial proposal, the AER's draft determination, Ausgrid's revised proposal and, for comparative purposes, the forecast capital expenditure program that the AER approved in respect of the 2009-14 regulatory period ($2013/14).

Figure 1 – Total capital expenditure - AER allowance, actual and proposed - 2009-19 ($ million, 2013/14)



As illustrated above, the forecast capital expenditure amounts contained in this revised proposal are 55% less ($2013/14) than the forecast capital expenditure amounts that the AER approved in respect of the 2009-14 regulatory control period, and 15% less than Ausgrid's 30 May 2014 initial proposal.

Operating Expenditure (Chapter 6)

Ausgrid's revised operating expenditure reflects the following changes and initiatives:

- Forecast progressive improvements in labour productivity which grow to 26.6% by the end of the regulatory period.
- A change in the amount of some fixed divisional and corporate overheads allocated to operating costs as a necessary consequence of the reduced capital expenditure program.

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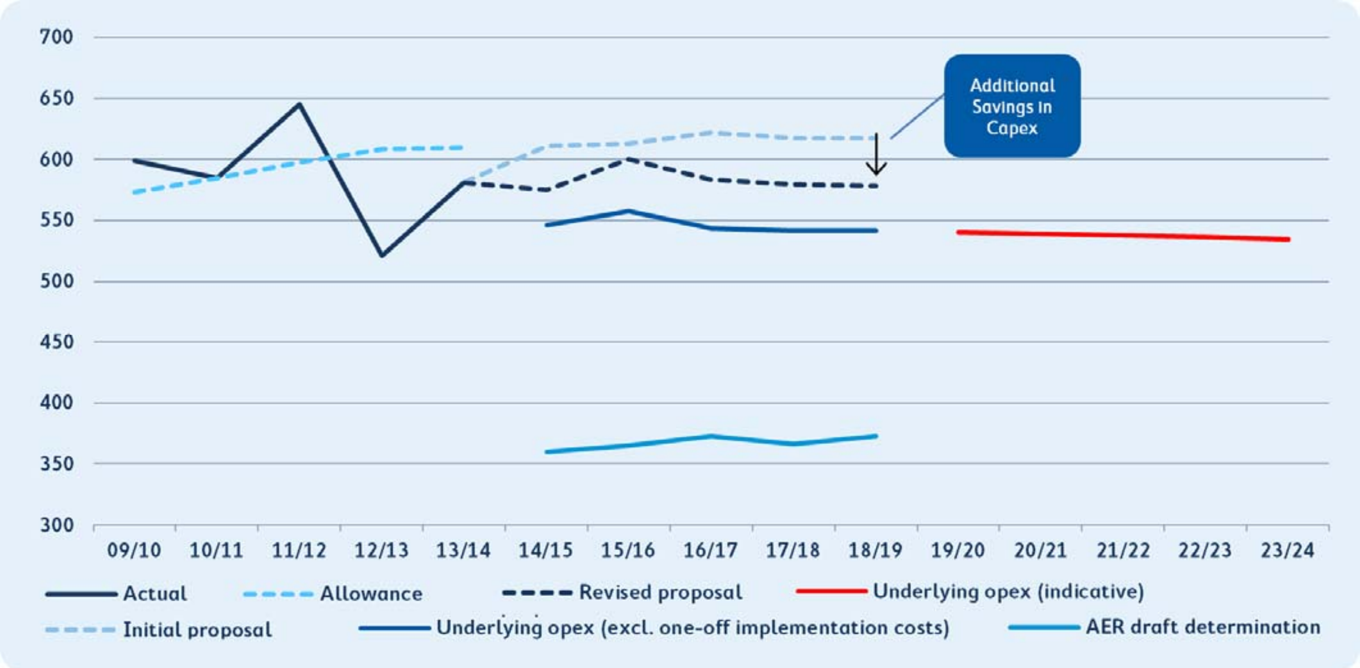
[2] These figures are inclusive of type 5-6 metering, ancillary network services and emergency recoverable works to ensure comparability. They are also stated in $2013/14.

- Forecast redundancy costs associated with a progressive reduction in our workforce and required to be paid as a regulatory obligation imposed by an enterprise agreement certified by the Fair Work Commission in accordance with the *Fair Work Act 2009*. These costs, which are an unavoidable consequence of achieving lower labour costs, will benefit consumers' long term interests by enabling lower total operating costs in the future.
- Labour cost escalation in line with the AER's draft determination.
- Forecast non-labour operating costs have been separately assessed for further efficiency improvement opportunities. Fleet costs have also been reduced proportionally with labour productivity improvements.

Figure 2 sets out the operating expenditure in Ausgrid's 30 May 2014 initial proposal, the AER's draft determination, this revised proposal and the AER approved operating expenditure for the 2009-14 regulatory period ($2013/14).

Figure 2 – Total operating expenditure - AER allowance, actual and proposed ($ million, 2013/14)[3]



As illustrated above, the operating expenditures contained in this revised proposal represent a 0.41% reduction ($2013/14) in the five year forecast operating expenditures relative to those that were approved by the AER for the 2009-14 regulatory control period and a 5.8% reduction compared to Ausgrid's initial proposal.

While there are significant and sustainable reductions in operating expenditure associated with labour productivity over the 2014-19 period and a reduced capital program going forward, these benefits are moderated by the obligation to pay redundancy costs associated with driving improvements in labour productivity. As illustrated in Figure 2 above, the long term interest of consumers are advanced by a reduced capital program and lower operating costs in the medium to long term based on sustainable labour productivity improvement, effective vegetation control and a risk based bush fire management program.

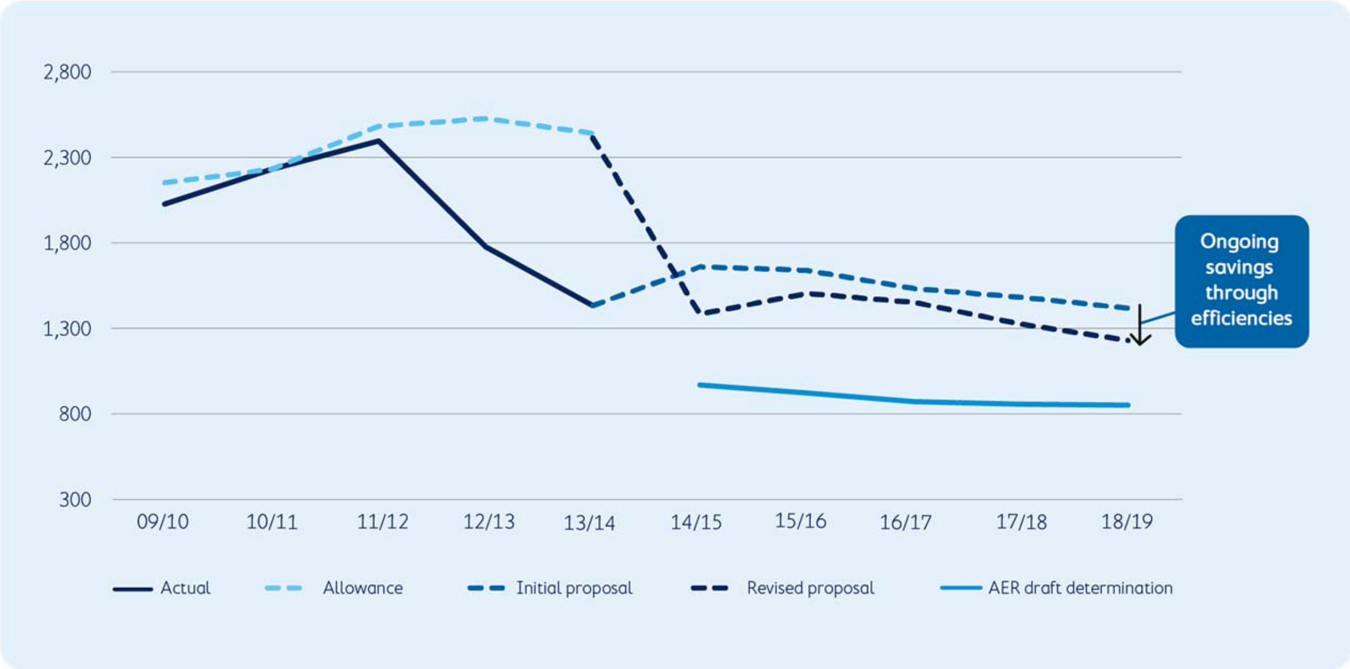
As noted, our revised forecast opex includes one-off redundancy costs. Figure 2 highlights the lower underlying operating costs once the one-off implementation costs are excluded. It also provides an indication of the opex profile for the subsequent regulatory period 2019-24. This indicative profile encapsulates the ongoing benefits of the labour productivity resulting from the efficiency programs over the 2014-19 period.

Total Expenditure

Figure 3 shows Ausgrid's total expenditure (capital and operating) for the relevant periods. In real terms ($2013/14) our revised proposed is 41.4% lower than the 2009-14 programs approved by the AER and 11.4% lower than our initial proposal.

[3] The increase and subsequent decrease between 2011/12 and 2012/13 mainly relates to movements in employee leave provision accounts for the financial years.

Figure 3 – Total expenditure – AER allowance, actual and proposed for 2009-19 ($ million, 2013/14)



Rate of return (Chapter 7)

Ausgrid proposes a revised rate of return on capital of 8.85%, which is commensurate with the minimum efficient financing costs for a DNSP with a similar degree of risk as that which applies to Ausgrid over the 2014-19 regulatory period. The revised rate of return has been developed to promote long-term stability both for customers and equity holders.

In summary:

- We propose an allowed cost of debt of 7.98%, which has been calculated consistent with the ten year trailing average approach set out in the AER's final rate of return guideline. This estimate is based on bond yield data for BBB+ and BBB rated Australian corporate bonds issued from 1 January 2004 to 31 December 2013.
- The AER has determined that the cost of debt is to be estimated using a ten-year trailing average approach that will be subject to annual updates throughout the regulatory control period. This position is consistent with the approach in our initial proposal, and as such we accept the AER's draft findings on this matter.
- We have fundamental concerns with the AER's proposed ten year transition path to the trailing average. As Ausgrid has historically issued debt on a benchmark efficient staggered portfolio basis, the AER's debt transition would significantly under compensate Ausgrid based on current forecasts of yields on ten-year BBB corporate bonds and the cost of our existing portfolio. This results in significant losses being incurred by Ausgrid over the entire 2014-19 regulatory period. We consider that the application of the AER's proposed debt transition would not allow us the opportunity to recover at least our efficient and realistic costs of debt finance, which is inconsistent with the revenue and pricing principles outlined in section 7A of the National Electricity Law and should not be applied to Ausgrid.
    - The AER's proposed transition path would mean that the benchmark efficient approach for setting the allowed cost of debt (the trailing average approach) would not be fully implemented for 10 years, i.e. not until the 2024-29 regulatory period. We consider that a debt transition that is not fully unwound until 1 July 2024 is not reasonable for firms that already issue debt on a staggered portfolio basis.
    - If the AER applied its proposed transition to firms that issue on a staggered portfolio basis, it would by its own measure be setting revenue allowances on an inefficient basis and providing incentives inconsistent with the benchmark efficient approach to debt portfolio management.
- We propose an allowed cost of equity of 10.15%, which has been estimated using internally consistent estimates of parameters within the capital asset pricing model (CAPM). The cost of equity has been selected from a reasonable range that takes into account prevailing market conditions and evidence from relevant financial models including the CAPM (both the Sharpe-Lintner and Black versions), the dividend growth model (DGM) and the Fama-French 3 Factor Model (FFM).

Ausgrid's revised proposal contains an allowed rate of return on capital of 8.85% that is consistent with the approach set out in our initial proposal updated for movements in various market parameters. Chapter 7 outlines our rationale for why the AER should not apply a transition to the the trailing average approach for setting the allowed return on debt, recognising the benchmark efficient practice and the individual circumstances of Ausgrid. Chapter 7 also outlines why the AER's return on equity has not adequately taken account of all relevant data and financial models as required by the NER.

Incentive Mechanisms (Chapter 3)

Ausgrid considers that unless the AER accepts our revised capital and operating expenditure proposals, the Efficiency Benefit Sharing Scheme, the Capital Expenditure Sharing Scheme and the Service Target Performance Incentive Scheme should not apply for the reasons set out below.

Efficiency Benefit Sharing Scheme (EBSS)

The AER's draft determination states that no expenditure will be subject to the EBSS in the 2015–19 regulatory control period. The AER made this decision because of its forecasting approach to opex and the likely incentives Ausgrid already faces to improve its efficiency. The AER noted that this also means that no expenditure will be subject to the EBSS in the 2014/15 regulatory control period.

Our contention is that if the AER makes the correct opex decision, it would have no need to suspend the application of the EBSS. The AER's decision is inconsistent with its previously proposed approach. We consider that the AER's reasoning demonstrates that the substitute forecast opex is unachievable, and there would be a high risk of substantial penalties if an EBSS was applied. As we demonstrate in Chapter 6 of this revised proposal, the AER's responsibility is to set an opex allowance that reasonably reflects efficient and prudent costs to enable Ausgrid to achieve the opex objectives. If the AER made such a decision, then an EBSS incentive would provide a symmetrical incentive.

If the AER, however, decides to not accept our proposal and to substitute a lower (unachievable and insufficient) amount .which we consider would be contrary to the NER, then we agree that an EBSS would not provide a symmetric incentive (i.e. one in which there is a similar likelihood of achieving rewards or penalties), and therefore should not apply.

In addition, the AER now seeks to exclude carry overs of efficiency gains and losses caused by movements in provisions in the draft decision for Ausgrid for the 2015/16 to 2018/19 subsequent regulatory control period by claiming that provisions are an accounting treatment and do not actually represent an expenditure (as required by clause 6.5.8(a) of the NER) from which an efficiency gain or loss can be determined. That is, the AER considers that there is a degree of artificiality to such costs. In our view movements in employee related provisions do represent actual costs incurred by Ausgrid.

There is no rule that explicitly provides discretion for the AER to retrospectively introduce additional excluded cost categories for the EBSS or to revise or review adjustments, and there are strong arguments that the AER is not entitled to do so.

In addition, the February 2008 EBSS that applied to Ausgrid in the 2009-14 regulatory control period does not provide for the AER to exclude an additional cost category after the relevant final determination. That is, any decision to exclude an additional category of costs should have been contained in the 2009-14 final determination and not made by the AER after the event.

We consider firstly that such a retrospective exclusion would be contrary to the purpose of incentive based regulation and would not be consistent with 'fair sharing' of efficiency gains and losses under the EBSS. A DNSP cannot be incentivised by retrospective changes to a scheme because the actions that are sought to be incentivised or dis-incentivised have already occurred. Incentives are created by the promise of rewards or penalties. Retrospective changes to either the excluded cost categories or revisions of adjustments made by the DNSPs may instead dis-incentivise DNSPs going forward because there is a risk that the EBSS (or any other regulatory decision) as it is applied to the NSW DNSPs in the future may be different to how the AER represented that the EBSS would apply when it was introduced.

If the EBSS is not applied by the AER in a manner consistent with its previous representation that provisions were not an excluded cost category, then there is a risk that DNSPs will not believe that the AER has the regulatory commitment to keep other regulatory promises. Equally, if revisions of adjustments are made at the end of a regulatory control period, then DNSPs may consider that there is a risk that the AER would review or revise other efficiency gains or losses made. Both these factors jeopardise the incentive features of the EBSS.

Capital expenditure sharing scheme (CESS)

The CESS as set out in the AER's November 2013 capital expenditure incentive guideline provides reward/penalty for efficiency gain/loss with respect to capital expenditure. In its distribution determination for the transitional year (i.e. 2014/15), and consistent with the transitional rules, the AER specified that no CESS would apply in 2014/15. The AER proposes to apply its CESS in the 2015-19 regulatory period in accordance with its published guidelines.

Ausgrid's initial proposal was to apply the CESS in the 2015-19 regulatory period, consistent with the AER's proposed approach as stated in the AER's stage 2 framework & approach (F&A) paper. The AER's draft determination is consistent with the F&A paper and our initial proposal, and on this basis we have not revised our proposal.

Consistent with the approach to EBSS, if the AER decides to not accept our capital expenditure proposal and instead substitutes a lower amount, we consider that a CESS would not provide a symmetric incentive (i.e. one in which there is a similar likelihood of achieving rewards or penalties) and therefore should not apply.

Service target performance incentive scheme (STPIS)

Our initial proposal agreed with the AER applying a scheme from 2015/16 onwards, and set out a revenue at risk of 2.5%. The AER's draft decision has applied a STPIS from 2015/16 onwards with a revenue at risk of 2.5% consistent with our proposal and the Framework & Approach paper. The AER has also accepted our proposed revenue at risk for each parameter.

However, the AER has not accepted some of our proposed design elements. Attachment 3.02 sets out our revised proposal for the reliability parameters. We do not agree with the AER's approach to set a more onerous target compared to our past performance based on an incorrect supposition that investment undertaken in the 2009-14 period will have an impact on our targets in the 2014-19 period. Rather, the AER should set reliability targets based on our average performance over the past five years.

In light of the AER's adjustment to our STPIS reliability targets and its proposed real reduction to our future capital and operating expenditure programs of 42% and 39%, respectively, against our initial proposal, we do not consider that we would be in a position to meet our current reliability targets. We have sought advice from Jacobs Group Australia in relation to the reliability and STPIS impacts of the draft determination (Attachment 1.01). Modelling by Jacobs[4] confirmed that in those circumstances reliability would materially worsen compared to previous forecasts, with further degradation in following regulatory periods.

A STPIS incentive framework in the 2014-19 period would not provide a symmetric incentive (i.e. one in which there is a similar likelihood of achieving rewards or penalties) and therefore we consider that unless the AER accepts our revised capital and operating expenditure forecasts, the STPIS should not apply.

Alternative control services (Chapter 8)

We have not accepted all elements of the AER's decisions on charges for public lighting, ancillary network services and annual metering services. As requested by the AER, we have provided additional information to demonstrate we will incur incremental administrative costs that would be appropriately recovered through an administration fee.

In relation to our public lighting services, the AER has misinterpreted our proposal by substituting the failure rate of the lamp or light bulbs from its last determination to calculate the rate at which we must repair an entire lighting structure. This revised proposal clarifies that the cost of repairs is not restricted to when a lamp fails and there are many other reasons why a lighting structure needs to be repaired. This proposal maintains an opex forecast to repair lights that fail even when the failure is not related to the lamp itself.

Ausgrid's annual revenue requirements (Chapter 4)

The table below sets out the revised smoothed annual revenue requirements for Ausgrid compared to the AER draft determination and Ausgrid's 30 May 2014 initial proposal.

Table 1 – Revised smoothed annual revenue requirement ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Initial Proposal	2,313.8	2,372.2	2,424.6	2,498.8	2,579.6	12,189.1
AER draft determination	2,208.8	1,576.7	1,619.0	1,662.5	1,707.0	8,773.9
Revised proposal	2,208.8	2,338.5	2,403.9	2,471.2	2,540.5	11,962.8

Note: Numbers may not add due to rounding.

As illustrated in Table 1, the smoothed annual revenue requirements in this revised proposal over the five years are $226.3 million (1.9%) lower than those contained in our initial proposal.

Critique of AER's draft determination

The AER's deterministic use of a flawed benchmarking model in its draft determination for Ausgrid has resulted in reductions to submitted operating expenditure of 39%. Ausgrid's Chief Operating Officer has signed a statement[5] as part of this revised proposal that he cannot maintain a safe and reliable network based on the AER's draft determination. The AER is accountable for the provision of adequate funds to maintain a safe and reliable network.

The view of Ausgrid's Chief Operating Officer as expressed in his statement is as follows:

[4] Attachment 1.01 - Jacobs - Reliability Impact Assessment

[5] Attachment 1.02 - Statement of Chief Operating Officer of Ausgrid (CONFIDENTIAL)

In my opinion, based on current information, the reductions proposed by the AER would likely lead to substantial under investment by Ausgrid in both capital and operating expenditure, and would compromise the safety, the reliability and the ongoing sustainability of its network.

In light of the AER's draft decisions, Ausgrid has made a number of revisions to its proposal so as to incorporate the substance of the changes required to address the matters raised by the draft determination or the AER's reasons for it. We have also incorporated up-to-date information not available at the time of the initial proposal and have reviewed our expenditures to ensure the latest information on the impact of our efficiency programs has been reflected in our expenditure forecasts. This includes updates to financial data and result in a lower annual required revenue compared to our initial proposals.

There are significant elements of the draft determination that we have not adopted for four key reasons:

1. Public and employee safety (Chapter 1)

The draft determination did not include a safety risk assessment of the potential for increased network asset / system failures as a result of the proposed reduction in 'resources', or the extent to which these reductions would have adverse risk consequences to the health and safety of workers and members of the public. In making the draft determination, the AER did not have sufficient regard to Ausgrid's legislative obligations under the Work Health and Safety Act 2011 (NSW) (WHS Act), in particular to meet the "primary duty of care".

The AER's proposal to accept the safety consequences of higher rates of network asset failure and an increase in local service interruptions (blackouts) is neither consistent with the NEO nor the objectives of WHS legislation. The safety risk assessment undertaken on behalf of Ausgrid (by 2RA) found that it is foreseeable that safety risks for Ausgrid workers and members of the public will increase from the AER's draft determination where it is proposed that Ausgrid's operating and capital expenditure be significantly reduced.

Based on consideration of all factors, we are of the opinion that the proposed operating and capital expenditure allowed for in the draft determination would preclude Ausgrid from complying with its obligations under the WHS Act. We are also of the opinion that if the AER is aware of the safety impacts of the proposed operating and capital expenditure allowed for in the draft determination and it makes its final determination allowing for these same levels irrespective of these safety impacts, it will be in breach of its primary duty of care under the Cth WHS Act.

Of particular concern is the reduction in Ausgrid's vegetation control program implied by the AER's 39% aggregate reduction in operating expenditure. The Commissioners of NSW Fire and Rescue and NSW Rural Fire Service[6] have both expressed in writing a concern over proposals to substantially reduce this operating expenditure and the possible impact on vegetation management in bushfire-prone areas of NSW and whether detailed risk assessments of the broader impacts of the AER's draft determination have or will be conducted by the AER.

2. AER approach to benchmarking is untested and unreliable (Chapter 1 and 6)

In its draft determination, the AER made retrospective and significant reductions in operating expenditure predominantly driven by the deterministic use of the unreliable, untested and unsafe Economic Insights (EI) report dated 17 November 2014. The AER breached its obligations under the rules by failing to publish the first Annual Benchmarking Report by 30 September 2014. This failure delayed the publication of the report by almost two months and resulted in no consultation or engagement with Ausgrid on how the AER would use the report to assess (and apparently determine) the forecast operating expenditure. This is unsatisfactory and prejudicial to the interests of Ausgrid and inconsistent with the NER.

Further, the AER engaged Economic Insights to review whether Ausgrid's opex base year should be adjusted and whether a productivity factor should be applied to the forecast period. Economic Insights did not contact Ausgrid to discuss any of the issues, nor did its report to the AER show that it had reviewed our initial proposal.

It is concerning that the AER's draft determination relies heavily on the Economic Insights report to support its reductions to Ausgrid's opex and at the same time Economic Insights relies heavily on the AER's draft determination regarding the operating environment to support its conclusions. That is, both reports are based on unsubstantiated positions.

The rules require the AER to have regard to benchmarking in making its operating expenditure decision. However, we consider that the way in which the AER has approached benchmarking in our draft determination is not consistent with the rule framework. We consider that the AER has misdirected itself in its pursuit of an econometric benchmarking model to produce an outcome (number)

[6] Attachments 1.03 (Commissioner - Fire and Rescue NSW: Letter to CEO of NNSW) and 1.04 (Commissioner - NSW Rural Fire Service: Letter to CEO of NNSW)

that it could use to derive opex without also undertaking appropriate safeguards in the form of data preparation and testing of modelled results. This has led to a poor decision that is not consistent with the rules or the NEO.

The rules require the AER to accept the forecast of required operating expenditure if it reasonably reflects the operating expenditure criteria. The criteria include the costs that a prudent operator would require to achieve the operating objectives and a realistic expectation of the cost inputs required to achieve those objectives. This requires the AER to consider the individual circumstances of the business.

The rules require the AER to have regard to the individual circumstances of the business and the realistic expectation of costs inputs. To do so, the AER should have used benchmarking to identify areas where further investigation might be warranted. Instead, the AER has used an econometric model as a tool by which to derive base year operating costs. This decision is particularly unwise given the known difficulties of benchmarking within the Australian context – a context known for its very small sample and for its heterogeneity.

The AER has erred in its application of benchmarking in the NSW determinations. It has made two decisions that will have far reaching consequences if they proceed unchecked. The first of the AER's critical decisions was to rely on benchmarking exclusively to set the base year opex for each company. The AER did not, as in previous determinations undertake a detailed assessment of components of opex or commission an engineering review of maintenance programs. Instead, the AER relied on an untested benchmarking regime to mechanistically derive very large adjustments to the base year opex for the NSW and ACT distributors.

The second decision and critical mistake was that the AER did not undertake adequate preparation for the application of benchmarking. The AER did not apply itself in sufficient detail to the consistency of reporting in the RIN or the comparability of international data used in its models. The AER did not appropriately test the models developed or the input variables selected. The AER did not provide sufficient time for peer review of their benchmarking approach and did not undertake any due diligence assessment of the consequence of the recommended reductions.

We believe that the results contained in the Economic Insights report are entirely unreliable and should play no role in the AER's final determinations. The operating expenditure proposed by the AER in its draft determination is unrealistic, does not take account of the revenue and pricing principles in the NEL and is not sufficient to meet Ausgrid's regulatory and legally binding contractual obligations.

Ausgrid has undertaken expert reviews of the AER's approach, benchmarking model and conclusions. These reviews by Frontier Economics[7], Huegin[8], David Newbery[9], Pacific Economics Group Research[10], Advisian[11] and PWC[12] have provided compelling evidence that the AER's approach and conclusions are unsafe and unreliable.

3. AER has discounted our substantial body of evidence about consumers' preferences (Chapter 2)

The AER has discounted the substantial body of evidence gathered by Ausgrid to assess and test consumer and stakeholder preferences.

These preferences form the basis of our five-year proposal and are the result of Ausgrid's consumer and engagement strategy, designed well ahead of the publication of the AER's consumer engagement guideline in November 2013.

The strategy identified discrete consumer cohorts and used multiple methods to gather, assess and record consumers' preferences. It also used well-accepted engagement techniques, including quantitative and qualitative research, face-to-face deliberative planning workshops with residential and small business consumers, discussion forums with stakeholders, meetings with councils, forums for Accredited Service Providers and an innovative Facebook campaign for social media users.

Three consistent priorities emerged as a result of these multiple engagement initiatives: safety, reliability and affordability. In the interests of transparency, Ausgrid's website contains reports on each initiative.

[7] Attachment 1.05 - Frontier Economics - Review of AER's econometric models and their application in the draft determination for Networks NSW

[8] Attachment 1.06 - Huegin - response to draft determination on behalf of NNSW and ActewAGL - Technical response to the application of benchmarking by the AER

[9] Attachment 1.07 - David Newbery, Cambridge Economic Policy Associates: Expert report, Jan 2015

[10] Attachment 1.08 - Pacific Economics Group (PEG) - Statistical Benchmarking for NSW Distributors, Jan 2015

[11] Attachment 1.09 - Advisian - Review of AER benchmarking, January 2015

[12] Attachment 1.10 - PWC - Independent Expert Advice on appropriateness of RIN data for benchmarking comparisons, Jan 2015

Despite this body of evidence, the AER has largely rejected feedback collected from more than 2000 Ausgrid consumers and stakeholders, electing instead to rely on feedback provided in 21 submissions relating to our initial proposal. Further examination shows many claims in these submissions to be unsubstantiated, incorrect or inconsistent with engagement commissioned by Ausgrid before and after our initial proposal was lodged.

In November 2014 Ausgrid commissioned further research into customer preferences using a Discrete Choice Experiment – or choice modelling – to gain a better understanding of consumers' willingness to pay for services. A report on the preliminary findings of this research is provided as Attachment 2.11.

The choice experiment designed by Ipsos Social Research Institute presented a number of scenarios to participants reflecting different network charges and service offerings. These were then rated according to relative acceptability.

The results of this research validate previous research and engagement initiatives, which showed that while customers are concerned about price and affordability, the majority are not willing to trade reliability, safety and service for lower charges.

Importantly, a scenario featuring network charges based on the AER's draft decision and relative reductions in service standards due to reduced revenue was the most unacceptable statement of all presented to Ausgrid's customers. The report found this outcome indicated that:

> *...customers are unwilling to sacrifice service offerings (particularly in terms of number and duration of unplanned blackouts and service restoration times) for a large reduction in quarterly network charge.*[13]

The choice modelling research revealed that while price is a key driver for customers' choice of potential service offerings, changes in service offerings – particularly the number and length of unplanned blackouts, service restoration times and pole maintenance – are also key drivers.

These findings provide further insight into consumer preferences, and reinforce the conclusions drawn from earlier engagement initiatives used to support our initial revenue proposals.

Finally, the AER's notion of more "regulated blackouts" diminishes the serious responsibility Ausgrid has to do all that is "reasonably practicable" for the wellbeing of its life support customers spread across its network. Under the National Energy Customer Framework, DNSPs have special obligations to ensure that life support customers are provided with information to assist them to prepare a plan of action in case of an unplanned interruption and are given written notice of any planned interruptions.

Any view that vulnerable customers would be appropriately compensated for increases in unplanned interruptions by a Guaranteed Service Level payment designed around the frequency and duration of interruptions experienced by an average customer totally undermines the policy purpose of these provisions.

4. AER's failure to comply with the National Electricity Law

The NEL requires that the AER must take into account the revenue and pricing principles under section 7A of the NEL when exercising a discretion in making those parts of a distribution determination relating to direct control services. The revenue and pricing principles include the following:

- A regulated network service provider should be provided with a reasonable opportunity to recover at least efficient costs incurred in providing direct control network services and complying with regulatory obligations, requirements or making a regulatory payment (NEL section 7A(2)).
- A regulated network service provider should be provided effective incentives to promote economic efficiency in the investment, provision and use of the network (NEL section 7A(3)).
- 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 those services to which that price or change relates (NEL section7A(5)).

The ongoing uncertainty surrounding the deterministic use of benchmarking, the AER's unwillingness to consult with the industry on their benchmarking model and the long term positioning of an "efficient frontier" all add to the regulatory and commercial risks for the majority of electricity distributors operating in the National Electricity Market (NEM). We note that Standard & Poor's Rating Service (S&P)[14] monitors final regulatory outcomes in the sector. We consider that if the AER's final decision fails to provide full and timely recovery of efficient costs and adequate return on capital, it would likely represent a credit risk to the entire sector.

Evidence that the AER has not allowed for a return to Ausgrid commensurate with the revenue and pricing principles in the NEL include:

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[13] Attachment 2.11 - Ipsos research: Willingness to pay for network services, January 2015, p. 24

[14] Attachment 1.11 - "Standard and Poor's – Ausgrid Confidential Credit Assessment" (CONFIDENTIAL)

- ***The return on capital*** – Ausgrid's debt management practices are efficient and are consistent with the ten year trailing average approach determined by the AER to be the efficient approach to debt management that would be undertaken by a benchmark efficient entity with a similar degree of risk as Ausgrid. The AER's transition to the trailing average as outlined in the draft determination results in a cost of debt that is insufficient to cover the debt servicing costs of Ausgrid's current debt portfolio. In addition, the AER's cost of equity is at the low end of a reasonable range of returns having regard to alternative models. As discussed below, should the AER's regulatory determination result in a credit rating downgrade below Ausgrid's current stand-alone investment grade credit rating, unfunded debt servicing costs would be further increased and financial sustainability threatened.
- ***Insufficient operating expenditure allowance*** – the operating expenditure allowance contained in the AER's draft determination is unrealistic and insufficient to cover Ausgrid's labour costs (including voluntary redundancy costs) required to be paid by an enterprise agreement certified under the Commonwealth Fair Work Act. The allowance will not provide efficient funding to meet competitively bid and legally binding contracts for vegetation management, IT services, asset inspection and facilities management.
- ***Retrospective "true up"*** – the "true up" for the difference in the annual revenue requirement for the 2014/15 year determined in the AER's transitional distribution determination and the AER's draft determination of 27 November 2014 is $471 million (21%). The magnitude of this unexpected "true up" required in the remaining four years of the regulatory period further degrades the funding for the provision by Ausgrid of direct control network services for that period, and results in regulated revenues that are lower than those deemed by the AER in its draft determination as efficient for the four-year period ending 30 June 2019. The operating and capital expenditures determined by the AER for this transitional year are largely spent or committed and cannot be retrospectively reduced.
- ***Reduction in the capital program*** – the AER draft determination contains a $1.9 billion ($2013/14) or 42% reduction in the capital program compared to that proposed by Ausgrid and a $6.3 billion or 71.2% real reduction in the program approved by the AER for the 2009-14 regulatory control period. As a consequence of the reduced capital expenditure program a change in the allocation of some fixed divisional and corporate overheads will occur in accordance with Ausgrid's Cost Allocation Methodology (CAM) approved by the AER. The AER has made no provision for this consequential increase in forecast operating expenditure as a result of the nexus of the allocation of overheads with the capital program and in accordance with the AER's approved CAM of May 2014.
- ***More onerous STPIS targets*** – The AER draft determination proposed more onerous targets for network reliability compared with the five year rolling average from the AER's national STPIS regime and paradoxically reduced the capital and operating expenditure required to deliver this improved target. This element of the draft determination has introduced an asymmetrical bonus/penalty scheme and increased the regulatory and commercial risk of providing network services.
- ***Transforming our business*** – The AER has sought submissions in Ausgrid's draft determination on whether a "transition" to the AER's determined benchmarked efficient costs should be allowed and how any transition should be funded. This request is misdirected on a number of fronts:
  - The AER's benchmarking model is immature, unreliable and flawed and its calculation of efficiency is wrong. It should not be used in its current state.
  - The question of who should fund any 'transition' is the wrong question based on a false premise. The AER must determine what it considers to be an efficient allowance for operating and capital expenditure, i.e. an allowance that the AER is satisfied reasonably reflects the capital and operating expenditure criteria. This is the amount which should be reflected in allowed revenues. It is not open to the AER to set an amount that it knows is insufficient for the DNSP to meet the operating expenditure objectives. The question of who should fund a 'transition' does not arise when the AER correctly carries out its decision making under the rules.
  - The AER has incorrectly formed the view that it is not obliged to look at individual circumstances of a DNSP when it is assessing expenditure proposals. This position is based on an erroneous view of the effect of the AEMC 2012 rule change. That rule change did not remove the requirement of the AER to consider the circumstances of a DNSP. The AER's obligation is to address itself to the opex and capex criteria, which requires proper engagement with the DNSP's proposal and the circumstances set out in that proposal.
  - As part of Ausgrid's commitment to improve operating and capital efficiency, we propose progressive and sustainable improvements in labour productivity, including progressive reductions in our workforce. As with the majority of electricity distributors operating in the NEM, Ausgrid's Fair Work Commission certified enterprise agreement provides for a payment scale for employees accepting redundancy. Providing funding for legally binding redundancy payments is in the long term interests of consumers because operating costs are permanently reduced.
  - The NEL contains revenue and pricing principles that bind the AER to provide a return to Ausgrid commensurate with the regulatory and commercial risks of providing network services that enables a DNSP to recover "at least its efficient costs". This threshold obligation must be met in the AER's determination.

- The AER's draft determination used the Economic Insights benchmarking model to establish an "efficient frontier" for Ausgrid's aggregate operating expenditure and then determined the 2015-19 expenditure based on that efficient frontier. This approach removes the need for incentives to promote economic efficiency provided for in the NEL.

Financial sustainability

Ausgrid engaged Standard and Poor's Rating Service (S&P) to assess the financial impact of the AER's draft determination by examining the revenues contained in the AER's draft determination combined with the capital and operating costs as set out in this revised proposal, and our forecast interest costs. The confidential S&P report, provided as Attachment 1.11[15], outlines that under the draft decision revenue scenario, Ausgrid's stand-alone credit profile would not be sufficient to supportan investment grade credit rating (investment grade is anything above BBB-, below this level is sub-investment grade).[16]

As discussed in a confidential section of Attachment 1.12 from UBS, Ausgrid would face significant difficulties when trying to raise debt finance with a credit rating that is sub-investment grade, including a higher cost of debt, restrictive covenants, less liquidity and higher hedging costs. The pricing of sub-investment grade bonds in the Australian market results in sub-investment grade companies facing a significantly higher cost of debt than BBB or BBB+ rated firms. UBS's analysis also suggests that there is very limited liquidity for such bonds in the Australian market. These factors would mean that a sub-investment grade credit rating would significantly impair Ausgrid's financial sustainability.

To improve financial sustainability, Ausgrid would need to move to a significantly lower debt structure would require a material equity injection, which would not be a viable proposition for investors who would be asked to commit new funds to an operation generating low or negative equity returns.

The interests of consumers are served where regulatory decisions preserve the incentives for debt and equity capital providers to continue to invest in and support network service providers to provide a reliable, secure and safe service to consumers. In its draft determination the AER directly dis-incentivises debt and equity investors in network service businesses from continuing to invest in the businesses.

Clearly, the credit assessment outcome arising from the AER's draft determination is unsustainable and would seriously and adversely impact Ausgrid's financial sustainability. Ausgrid's revised proposal would provide sufficient revenues to facilitate a financially sustainable business while the AER's draft determination would not

[15] Attachment 1.11 - "Standard and Poor's – Ausgrid Confidential Credit Assessment" (CONFIDENTIAL)

[16] See https://www.spratings.com/about/about-credit-ratings/ratings-definitions-faqs.html

Feedback on proposal

A key vision underlying this proposal is to reflect on the views of our customers when preparing our proposal. Ausgrid's customers and stakeholders can provide feedback on this revised proposal through the following channels:

Channel	Details
Email	yoursay@ausgrid.com.au
Post	Chief Operating Officer GPO Box 4009 SYDNEY NSW 2001
Online	www.ausgrid.com.au/contactus

Customers can also provide feedback and comments on our proposal to the AER (www.aer.gov.au). Alternatively, customers may also like to contact us via twitter.com/ausgrid.

Ausgrid, Endeavour Energy and Essential Energy have also jointly launched a Facebook page (facebook.com/YourPowerYourSay) to engage customers on a wide variety of topics ranging from prices and reliability to vegetation management and street lights. We are also now seeking customer feedback about our regulatory proposals on the joint Facebook page.

1. Overview

In many instances, we have revised our initial proposal to address the changes required by the AER. We have not revised our proposal in cases where we have concerns with the validity of the AER's decision making, or where we disagree with the substance of the issues raised by the AER. We have provided information to satisfy the AER of our revised proposals in relation to each constituent decision. We consider that the revised proposal consequently meets the long term interest of our customers with respect to safety, reliability and affordability. In contrast, we consider the AER's draft decision if made final would result in adverse safety and reliability outcomes, and seriously and adversely impact Ausgrid's financial sustainability.

On 30 May 2014 we submitted our initial proposal to the AER. The AER published its draft determination on 27 November 2014. The National Electricity Rules (NER or "the rules") provide an opportunity to make revisions to incorporate the substance of any changes required to address matters raised by the AER's draft distribution determination or the AER's reasons for it.

The AER's draft determination identifies each of the constituent decisions it is required to make under the rules. For the most part, the AER rejected our proposal on each of these constituent decisions. Accordingly we have considered whether revisions are necessary to incorporate the changes required by the AER's draft determination in respect of these constituent decisions, and the reasons underlying these decisions. When reviewing the AER's decision we have sought to consider more up to date information that is available since submitting our initial proposal in May 2014. We have made revisions to our:

- Proposed service classification proposal, control mechanism and incentive mechanisms.
- Building block proposal for standard control services including forecast opex, capex, allowed rate of return, and other parameters used to derive our revised annual revenue requirement and X-factors.
- Alternative control services proposal for public lighting, metering and ancillary services.
- Arrangements for complying and reporting in our pricing proposals for the 2014-19 period.

While we have made changes to incorporate aspects of the AER's decisions which are set out in this revised proposal, we have also identified those aspects of our initial proposal that we have not revised in light of the AER's draft determination. In some respects, we consider that the AER has misconstrued its task under the regulatory framework, including the AER's perception that its task is only to determine an 'overall revenue allowance'. The AER's task is to make the correct constituent decision which, if made in accordance with the decision making framework, will provide a revenue stream that meets the NEO.

In terms of the AER's constituent decisions, we consider there are fundamental issues with its decision making process in respect of:

- Opex – The AER appear to have misunderstood the functions conferred on it by a rule change made by the AEMC in 2012. The AER have applied flawed benchmarking analysis as the primary basis for its decision to reject and substitute our proposal, without adequate consideration of materials provided in our proposal, or adequately addressing other factors in the rules.
- Allowed rate of return – The AER have adopted a transition approach to setting the allowed return on debt that is inconsistent with the benchmark efficient staggered portfolio approach to raising debt. In addition to this, the AER has not had regard to the relevant evidence submitted in our initial proposal on the required return on equity for a benchmark efficient energy network firm. Even based on its consideration of a subset of relevant information, the AER has adopted an internally inconsistent approach to estimating the cost of equity within the CAPM.

Overall, we consider that our revised proposal is consistent with the requirements of the NEL and the NER. We demonstrate that our revised expenditure forecasts are the efficient costs and reflect a realistic expectation of cost inputs to achieve the opex and capex objectives. In turn, this provides for the long term interests of customers by providing for safe and reliable services in the 2014-19 period. In contrast, we consider the AER's draft determination would not provide a sufficient revenue allowance to meet our safety and reliability obligations, and would seriously impact Ausgrid's financial sustainability.

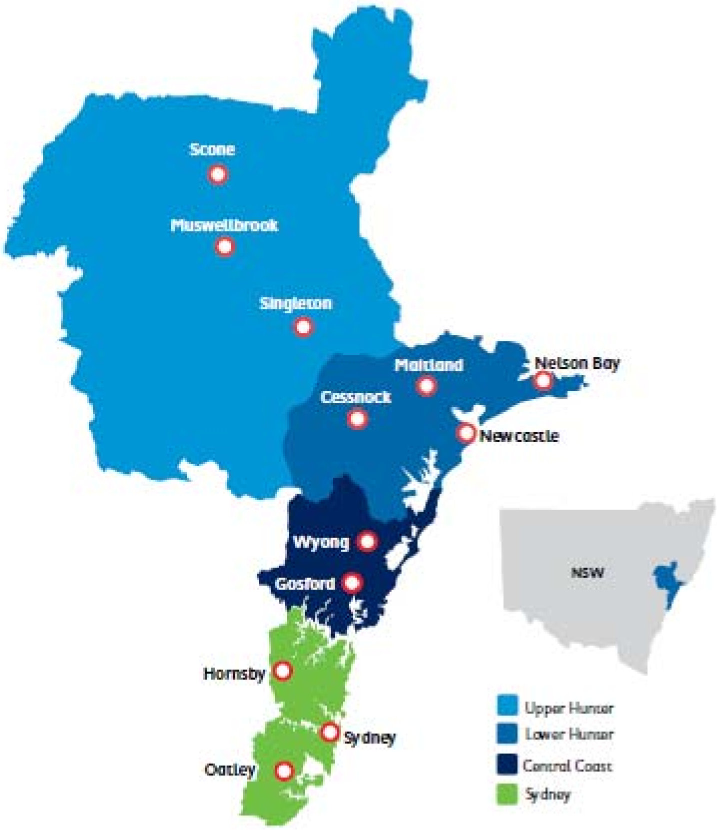
1.1. Background and purpose of revised proposal

Ausgrid is responsible for the safe and reliable distribution of electricity across a 22,275 square kilometre area on the NSW east coast. Ausgrid is a state-owned corporation that supplies electricity to almost half of the electricity customers in the state.

Our 1.65 million customers are located in some of the country's oldest and most densely populated areas, including the Sydney, North Sydney, Chatswood and Newcastle central business districts. It also supplies electricity to the major mining areas of the Hunter Valley and to fast growing residential areas on the Central Coast.

Ausgrid's distribution network is made up of large and small substations that are connected via high and low voltage powerlines, underground cables and power poles. Our operations are governed by national and state laws and regulations, and are paid for by electricity customers via their retail electricity bill.

Figure 4 – Map of Ausgrid's network



Summary of our initial proposal

As required by the rules we submitted our initial proposal to the AER on 30 May 2014.The AER's draft determination was published on 27 November 2014. The key highlights of our proposal were:

- We proposed a $12,212 million (nominal) in annual revenue requirements over the five year period. This directly translated to an average distribution network price reduction of 2.37% for all customers over the 2014-19 period. This is less the the forecast inflation rate.
- These real reductions (i.e. less than inflation) were driven by substantially lower capital requirements and operational efficiencies pursued by Ausgrid since 2009 and as a result of network reform program initiatives. They were also a result of lower borrowing costs following the Global Financial Crisis. We proposed a weighted average cost of capital of 8.83% applied to the 2014-19 period, compared to the rate of 10.02% for the previous regulatory period.
- The five year capital program will reduce from $8.4 billion approved by the AER for the 2009-14 regulatory period to a proposed $4.9 billion for the 2014-19 period – a reduction of 41%, which is 47% below the forecast rate of inflation over the five year period. The five year operating program will increase from $2.8 billion approved by the AER for the 2009-14 regulatory period to a proposed $3.3 billion (inclusive of efficiency implementation costs) for the 2014-19 period – an increase of 18%, which is 4% above the forecast rate of inflation over the five year period.
- Based on our proposed expenditure plans we expected current network reliability would be maintained for the regulatory period.

A central objective of our proposal was to meet the long term interests of our customers, with respect to safety, reliability and prices. Electricity networks require prudent maintenance and renewal to deliver a safe and reliable service in the long run. Our proposal used expert engineering judgement and granular budget analysis to identify the efficient level of expenditure and financial returns we required to maintain the health and safety of the network.

Our customer engagement activities played a crucial role in informing our view on what our customers want. The findings indicated a preference for maintaining reliable and safe services, at steady and stable prices.

Costs were clearly seen as the most important priority of our customers. With this in mind, our proposal focused on improving customer affordability by incorporating substantial efficiencies into our operating and capital programs for the 2014-19 period, including prioritisation of capital programs. This continued the extensive efficiency gains we had made in the 2009-14 period, where we had implemented cost savings across many dimensions of our business.

The outcome was a proposal that strived to contain average increase in our share of customers' electricity bill to or at below CPI, while maintaining the reliability and safety of the networks.

In support of our position, we compiled a detailed and fully substantiated regulatory proposal that complied with the information requirements in the rules and the AER's regulatory information notice (RIN). We also demonstrated how our proposal enabled the AER to be satisfied under the decision making criteria in the rules. For instance, we provided a detailed document addressing the capex and opex decision making objectives, criteria and factors.

AER draft determination

As required under the rules, the AER published a draft regulatory determination for Ausgrid on 27 November 2014. The AER noted that it had turned its mind to the question of what outcome would contribute to the achievement of the (National Electricity Objective (NEO) to the greatest degree. The AER considered that a decision will contribute to the achievement of the NEO to the greatest degree where the AER is satisfied that it delivers the best balance between the NEO's factors if it is satisfied that:

- The overall revenue allowance is consistent with the key drivers.
- The constituent components of a potential decision comply with the NER's requirements.

Overall revenue decision

The AER's decision is predicated on a view that recent changes to the National Electricity Law (NEL) and the NER meant that it has greater discretion, and encourages the AER to approach its decision making more holistically to meet overall objectives consistent with the NEO and Revenue and Pricing Principles. This led the AER to a view that it must specifically assess its overall revenue decision and its contribution to the NEO.

> *"This is the first draft decision we have made following changes to the NEL and NER in 2012 and 2013. The NEL and NER were changed to provide greater emphasis on the NEO and greater discretion to us. The amended NER allows and encourages us to approach decision making more holistically to meet overall objectives consistent with the NEO and RPPs. These changes also sought to give consumers a clearer and more prominent role in the decision making process.*
>
> *In 2013, the NEL was changed with similar aims in mind. Energy Ministers intend that the long term interests of consumers should be a key focus in determining our decision.[17] The changes also encourage analysis of the decision as a whole in light of the NEO when making constituent decisions.*
>
> *These legislative changes have made this decision different from our previous decisions. In particular, for the first time, we have specifically assessed our overall revenue decision and its contribution to the achievement of the NEO. We consider this is an appropriate change as we determine an overall revenue allowance."*

Accordingly, the AER's overview noted that it made a draft decision on the revenue that Ausgrid may recover from its customers in the upcoming 2015–19 regulatory control period. In total, the draft decision provides an allowance of $6,565.2 million ($ nominal), which represented a reduction of around 35% compared to Ausgrid's proposal.[18]

The AER noted that if it had accepted Ausgrid's proposal, Ausgrid would have been permitted to recover $10,092.5 million ($ nominal) from customers over the 2015–19 regulatory control period.[19] The AER was not satisfied that Ausgrid's proposed revenue would "contribute to the achievement of the NEO to the greatest degree" as it considered was required by the NEL and NER.

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[17] AER draft decision, Overview, p.16

[18] This excludes the transitional year 2014-15. See AER draft decision, Overview p.9

[19] AER draft decision, Overview, p. 9

The AER stated that Ausgrid's regulatory proposal puts forward revenue broadly in line with its current levels. The AER considered that the total revenue it proposed to allow in its draft decision reflected the underlying drivers of the costs of providing distribution services in Ausgrid's network area. Specifically, the AER noted that the circumstances have changed since the last regulatory period such that there has been a material easing in the pressure on costs since it made its last determination in 2009. Consequently, its draft decision provides for less revenue (on average) than what was approved in the last period.

The AER considered that the underlying drivers of the costs of providing network services in Ausgrid's network area are reflected in this draft decision include the following:

- Efficiency - The AER considered that its assessment of our proposal showed that there are further opportunities for Ausgrid's network services to be provided more efficiently. It considered that Ausgrid itself has identified inefficiencies in its business practices and proposed measures to reduce its costs going forward. The AER referred to its benchmarking work to highlight the extent of efficiencies that it considered were available.
- Better risk assessment - In the course of the AER's review of Ausgrid's proposal it came to the view that Ausgrid's risk management practices are overly risk averse and result in higher capex forecasts than is necessary.
- Demand – The AER noted that at the time of making its last determination in 2009, demand for electricity was expected to increase. However, these forecast increases did not eventuate. The AER noted that system peak demand in Ausgrid's network decreased on average by around 1.13% per annum over the past five years. The AER considered that recent forecasts suggest that the trend will continue downwards, at least for the next few years. The AER noted that this implies that Ausgrid is under less pressure to expand its network. These expectations indicate that only modest amounts of growth related expenditure will be required in the forthcoming period.
- Financial market conditions - The AER considered that the investment environment has improved since our previous decision. That decision, in 2009, was made at the height of uncertainty surrounding the global financial crisis. Interest rates and risk premiums are now materially lower than in 2009.

The AER's analysis took these underlying drivers into account and considered that this is reflected in the total revenue allowance it calculated. It stated that the total allowed revenue it determined was broadly in line with the trend in revenue that was allowed in the 2004–09 regulatory period. In 2009, there were a range of pressures that led to a step up in total allowed revenue. The AER noted that the draft decision reflected an easing in many of the underlying drivers that influenced the revenue outcome in 2009. By contrast, it found that Ausgrid's proposal did not adequately incorporate these underlying drivers.

The AER also noted that it had considered consumer preferences. It stated that stakeholders, including both businesses and consumer advocates, had been telling the AER that Ausgrid's proposal did not adequately incorporate their views and is not in the long term interests of consumers.

Constituent decisions

The AER is required to make a number of constituent decisions as part of its distribution determination. It considered that the constituent components of a potential decision comply with the NER's requirements. The AER's constituent decisions were identified in Appendix A of the AER's overview document of its draft determination. It referred to 3 key constituent decisions it had made:

- Rate of return – The AER was not satisfied that Ausgrid's proposed 8.83% rate of return achieved the allowed rate of return objective. It therefore did not accept Ausgrid's proposal. The NER defines the rate of return objective as follows: that the rate of return is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Providers in respect of the provision of many network services. Using the AER's rate of return guideline as its starting point, it allowed a rate of return of 7.15% (nominal vanilla) which, in its view, achieved the rate of return objective and will allow Ausgrid to fund its efficient network investment.
- Operating expenditure – The AER was not satisfied that Ausgrid's proposed forecast operating expenditure of $2,888.2 million ($2013/14)[20] reasonably reflected the opex criteria. It therefore did not accept Ausgrid's proposal. Its alternative estimate of Ausgrid's total forecast opex for the 2014–19 period that it is satisfied as reasonably reflecting the operating expenditure criteria is $1,758.5 million ($2013/14).[21] The main driver for the AER's substitute operating expenditure forecast was its alternative estimate for what it considered as representing an efficient base level of operating expenditure.
- Capital expenditure – The AER was not satisfied that Ausgrid's proposed total forecast capex of $4,421 million ($2013/14) reasonably reflected the capex criteria. It therefore did not accept Ausgrid's proposal. The AER's alternative estimate of Ausgrid's total forecast capex for the 2014–2019 period that they were satisfied reasonably reflected the capex criteria, was $2,546.4 million. The most significant difference in the AER's substitute capital expenditure forecast was a 43% reduction in the amount of forecast replacement expenditure (excluding overheads).

[20] Including debt raising costs.

[21] Includeds debt raising cost, AER draft decision, Overview, p.12

Purpose and structure of revised proposal

Our revised proposal responds to each constituent decision made by the AER, identifying where we have made revisions to our initial proposal to incorporate the substance of any changes required to address matters raised by the draft determination or the AER's reasons. To the extent that we have not made revisions to our proposal, we consider that this document also comprises a preliminary written submission on the AER's draft determination.

The structure of our revised proposal mirrors our initial proposal including:

- Our customers (Chapter 2) – This chapter does not directly relate to a constituent decision that the AER had to make but is a factor that the AER must have regard to in making its decisions on forecast opex and capex for standard control services.
- Services and Price Control (Chapter 3) – This chapter relates to the AER's constituent decisions on classification of services, and application of incentive schemes. These were matters the AER had also addressed as part of its Framework and Approach papers.
- Building block proposal (Chapter 4, 5, 6 and 7) – These chapters relate to the AER's constituent decisions on our building block proposal for standard control services. This including each building blocks and their underlying inputs, revenue and X-factors, and nominated pass through events. Chapter 5, 6 and 7 provide more detail on forecast capex, opex and allowed rate of return respectively.
- Alternative control services (Chapter 8) – This chapter relates to the AER's constituent decision on public lighting, metering and ancillary services.
- Control Mechanism, Tariff and Pricing arrangements and negotiating framework and criteria (Chapter 9) – This chapter relates to the AER's constituent decisions on compliance with the control mechanisms, reporting arrangements for pricing and negotiated framework.

Each chapter clearly identifies where we have made revisions to our proposal in light of the AER's draft determination and the AER's reasons. Where we have not revised our proposal, the initial proposal (including the relevant supporting documents) remain the current proposal and where appropriate we have provided further support to Ausgrid's position and why we have not accepted the AER's draft decision. We note that the supporting documents identified in this document also comprise our revised proposal.

1.2. Revisions to address changes required by AER's draft determination

The purpose of a revised proposal is to give an opportunity for a DNSP to revise its proposal in light of the AER's draft determination or reasons for it. With this in mind, we have reviewed each of the AER's constituent decisions where it has not accepted the position or value identified in our initial proposal. Where we consider that the AER's reasons are appropriate, we have revised our proposal. In the process of reviewing the AER's decision, we have also made revisions where new information is at hand that is relevant in deciding whether to revise our proposal for a matter raised by the AER.

The NSW DNSPs have carefully considered the findings of the AER's draft determinations and have revised our proposal in many areas to address matters raised by the AER's draft determination. We have put forward positions that we consider are preferable in meeting the requirements of the NEO to achieve long term benefits to customers and to maintain the safety and reliability of the networks. We have also considered latest information on the efficiencies expected from network reforms in the 2014-19 period, and have incorporated these into our forecasts for the 2014-19 period.

Each chapter of our proposal provides more information on the revisions we have made to our initial proposal.

- ***Chapter 2*** relates to customer engagement activities. We note that customer engagement is not subject to a constituent decision by the AER, but the extent to which our expenditure forecasts includes expenditure to address the concerns of electricity consumers identified during consumer engagement is a factor the AER must have regard to when making its assessment under the capex and opex criteria. However, we have addressed issues raised by the AER in respect of our customer engagement activities, and set out key findings from engagement activities we have undertaken since our initial proposal. Based on what customers are telling us, we do not accept the AER's contention that customers are prepared to trade safety and reliability for a lower price.
- ***Chapter 3*** notes that we have revised our proposal to incorporate the changes required by the AER with respect to service classification and control mechanisms. We have also largely accepted the AER's decision on the application of incentive schemes, with the exception of the reliability performance targets set by the AER for the Service Target Performance Incentive Scheme (STPIS) and the rejection of our proposed DM Benefit Sharing Scheme under the DMECGIS.
- ***Chapter 4*** identifies the revisions we have made to our building block parameters to address matters raised by the AER in respect of the opening asset base, and forecast capex and opex. We have not revised our proposal for the EBSS carry forward amount for 2009-14 and provide our reasons for this position. We have made consequential revisions to our proposal to our return on and return of capital, corporate depreciation, annual revenue requirement and X-factors to incorporate our revised inputs, and to incorporate latest information on the allowed rate of return.
- ***Chapter 5*** provides further detail on the revisions we have made to our forecast for capital expenditure. This includes revisions to our forecast based on changes to inputs and plans since the initial proposal was prepared, and those arising from analysis

and reviews undertaken in response to issues raised by the AER or stakeholders. As a result our revised capital expenditure forecast is 15% lower than our initial proposal.

- *Chapter 6* provides further detail on the revisions we have made to address the changes required by the AER for forecast opex. We raise fundamental concerns with the manner the AER undertook in its assessment of opex including its reliance on benchmarking data, which we consider invalidates its draft decision. When reviewing the AER's determination we also identified more current data that require revisions to our proposal. We consider that latest data shows that our efficiency programs will have a greater impact on our opex for 2014-19 through higher labour productivity. This reduces opex overall but has consequential impacts on stranded and exit costs.
- *Chapter 7* provides further information on how we addressed the changes required by the AER on the allowed rate of return. We identify issues with the manner in which the AER has not had proper regard to the current debt structure of the NSW DNSPs which we consider reflects an efficient approach to debt management, with the AER's approach to imposing a transition to the trailing average not providing sufficient revenues to meet the requirements of the NEL, NEO and NER. The AER has also not taken account of relevant evidence when setting its return on equity, which is inconsistent with the requirements of the rules and results in a return that does not adequately compensate equity holders and is insufficient to attract investment in infrastructure assets.
- *Chapter 8* sets out revisions to our alternative control services to address changes required by the AER. We have not revised our public lighting proposal for the changes required by the AER, but have made consequential revisions to our proposed prices to incorporate latest data on the allowed rate of return. We have reviewed the AER's changes on metering and ancillary services, and have largely not revised our proposal for the changes required by the AER.
- *Chapter 9* notes that we have not made significant revisions to our proposed compliance with control mechanisms and reporting arrangements for pricing purposes in the 2014-19 period to address changes required by the AER. Where appropriate we have raised issues with respect to the technical application of the control mechanism and associated formula.

In many cases we have not revised our proposal to address matters raised by the AER and have provided submissions to support the position set out in our initial proposal. At a high level, our concern has been that certain constituent decisions of the AER's draft determinations such as opex and allowed rate of return are inconsistent with the NER and have not led to a decision that satisfies the NEO in the NEL.

In this respect, the AER stated that its decision for the NSW and ACT NSPs are the first draft decisions that it has made following changes to the National Electricity Rules (NER) and the National Electricity Laws in 2012.

We consider that the AER has fundamentally misconstrued the decision making criteria and the discretion afforded to it by these changes. We have serious concerns about the AER's construction of the substantive effect of the 2012 rule change and amendments to the NEL, and hence its application of the amended rules to Ausgrid in its draft determination. There are two key areas where we consider there has been a misdirection in the AER's assessment.

Firstly, the AER has misconstrued the functions it must perform under the NEL and NER. The AER's determination is premised on determining an overall revenue amount, which in its view provides a preferable decision that is likely to satisfy the National Electricity Objective. As discussed in section 1.2.1 below, we consider that the AER is misdirected in applying such an approach to make a draft determination:

- Section 16(1)(d) is predicated upon the existence of 2 or more decisions that will or likely to contribute to the achievement of the NEO. It is only when this precondition is satisfied that the NEL then require the AER to make a choice on a decision that achieves the NEO to the greatest degree.
- The AER's approach to setting Ausgrid's annual revenue requirement is incorrect. Whilst the total revenue for each year of a regulatory period is a key constituent decision that the AER has to make, the NER is very clear on how this annual revenue amount is to be determined. Most importantly, it is determined by aggregating the key inputs that make up the revenue amount (building block approach) with each input having its own decision-making framework and criteria.

Our second concern is that the AER has not properly carried out its decision making tasks required under the NER with respect to certain constituent decision including forecast opex and allowed rate of return. We have concerns with the validity of the AER's draft decision both in terms of meeting the requirements of the NER, and in terms of the substance and merits of such decisions. These concerns are set out in more detail in section 1.2.1 below.

- For forecast opex we are particularly concerned with the AER's application of its benchmarking, which we show cannot be relied upon to set forecast opex in the deterministic manner proposed. Further, the AER's failure to publish its first annual benchmarking report in accordance with the requirements of the rules has severely compromised the NSW DNSPs' ability to adequately respond to the outcomes of the report in their revised proposals. The transitional arrangements put in place by the AEMC following the 2012 rule change clearly contemplate that NSW DNSP would have a period of 2 months within in which to consider the AER's first benchmarking report given the timeframes for the regulatory process set out in clause 11.56.4(o) of the rules and do not contemplate this consideration being done at the same time as preparing a revised proposal.

- For the allowed rate of return, we consider the AER has not made a decision in accordance with the rules. We outline our concerns fully in Chapter 7.

Concerns with AER's considerations on its role under section 16(1) of NEL

In its draft decision, the AER stated that[22]:

> *This overview sets out why we are satisfied that our draft decision will contribute to the achievement of the NEO to the greatest degree. Specifically we address section 16 of the NEL which sets out how we must exercise our regulatory functions.*

Below, we set out our consideration on the above views of the AER on the tasks it is required to carry out by the NEL and the NER, in particular:

- the manner in which it performs its functions as specified in clause 16(1)(d) of the NEL.
- The decision it made in the draft decision on the annual revenue requirement.

We are concerned about the manner in which the AER has performed its functions under clause 16(1)(d) of the NER and with the AER's perception that it task is only to determine an 'overall revenue allowance'. We address these further below.

Preferable decision

The AER decided to reject the total revenue for the 2015-19 proposed by Ausgrid and substituted for an amount that is 34.9% less than that proposed by us. The AER is satisfied that its substituted revenue amount contributes to the achievement of the NEO to the greatest degree[23]. It also contends that it has done this on the basis of clause 16(1)(d) of the NEL which states:

> *If the AER is making a reviewable regulatory decision and there are 2 or more possible reviewable regulatory decisions that will or are likely to contribute to the achievement of the national electricity objective-*
>
> *(i) Make the decision that the AER is satisfied will or is likely to contribute to the achievement of the national electricity objective to the greatest degree (the preferable reviewable regulatory decision)*
>
> *(ii) Specify reasons as to the basis on which the AER is satisfied that the decision is the preferable reviewable regulatory decision.*

We considered that the AER has misunderstood its task under the NEL and NER and consequently has not properly carried out this task in accordance with the above requirement of the NEL.

Clause 16(1)(d) is predicated upon the existence of 2 or more decisions that would meet the NEO. It is only when this precondition is satisfied that the NEL then requires the AER to make a choice on a decision that achieves the NEO to the greatest degree. This precondition is clearly recognised by the AER when it stated:

> *The NEL anticipates that there may be two or more possible overall decisions that will or are likely to contribute to the achievement of the NEO. In those cases, we must make the decision we are satisfied will contribute to the achievement of the NEO to the greatest degree.(page 29)*

The AER rejected our proposal and substituted with its own decision. The AER concluded that:

> *We are not satisfied that Ausgrid's proposed allowed revenue would 'contribute to the achievement of the NEO to the greatest degree' as required by the NER.*

The AER then replaced Ausgrid's proposed revenue with that calculated by it and then sought to justify this decision as one that would contribute to the achievement of the NEO to the greatest degree. We consider that the AER has misdirected itself as to the nature and purpose of clause 16(1)(d) of the NEL or alternatively this clause cannot be invoked because the precondition for its application does not exist. Having rejected Ausgrid's proposal as not contributing to the achievement of the NEO, the AER has not identified two or more possible decisions that it considers would or are likely to contribute to achievement of the NEL. Consequently, there is not two or more decision that achieves the NEO, a condition that would then necessitate a decision by the AER to choose between one and specify reasons for such choice.

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[22] AER's draft decision, Overview page 29

[23] AER's draft decision, Overview page 29

Additionally, instead of identifying two or more decisions that would achieve the NEO for the regulatory control period under consideration (i.e. 2015-19) it appears to us that the AER contrasted its substituted revenue allowance decision against the revenue it allowed for the previous regulatory control period (i.e. 2009-14) and justified its reasons against the underlying drivers between the two periods. We consider this is an incorrect application of clause 16(1)(d) which requires the identification of two or more possible decisions that achieve the NEO for the regulatory control period under consideration, and reasons for the choosing one over the other. Clause 16(1)(d) does not conceive the task at hand to be one of comparing decisions between periods. This misapplication is apparent in the following AER's statement:

> *The total allowed revenue we have determined is broadly in line with the trend in revenue that was allowed in the **2004-09 period** (emphasis added). In 2009, there were a range of pressures that led to a step in total allowed revenue. This draft decision reflects an easing in many of the underlying drivers that influenced the revenue outcomes in 2009. By contrast, we have found that Ausgrid's proposal does not adequately incorporate these underlying drivers.*[24]

Our concerns about the AER's decision and justification are further exacerbated by the AER's constituent decisions under Chapter 6 of the NER. As can be seen in the statements below the AER considers that compliance with the NER in relation to 'constituent components of a potential decision' would aid in the finding that a particular decision would be a preferable reviewable regulatory decision.

> *Chapter 6 of the NER provides specifically for the economic regulation of distributors. It includes detailed rules about the constituent components of our decisions, which are intended to contribute to the achievement of the NEO.*
>
> *Consistent with Energy Ministers' views, we consider a decision will contribute to the achievement of the NEO to the greatest degree where we are satisfied that it delivers the best practice between the NEO's factors. To assess this, we especially consider whether we are satisfied that:*
>
> - *the overall revenue allowance is consistent with the key drivers.*
> - *the constituent components of a potential decision comply with the NER's requirements*

Setting of annual revenue requirement

The AER has not correctly approached its decision making with respect to determining the annual revenue requirement for Ausgrid. The AER has taken the mistaken approach that it determines the revenue allowance in some way separately from the constituent decisions which make up that allowance. Ausgrid contents that this approach is incorrect and not supported by the rules.

At the outset, we note that the AER refers to 'constituent components of a potential decision'. We wish to point out that the distribution determination is predicated upon constituent decisions, each decision with its own decision making criteria. They are decisions on their own which together form the distribution determination, and not components of an overall discretionary decision as seems to be implied by the AER. Whilst the AER's building block determination is a component of a distribution determination[25], it is clear that the annual revenue requirement must be determined using the building block approach and each of the building blocks set out in clause 6.4.3 of Chapter 6 of the NER. As we have previously noted, the AER stated:

> *These legislative changes have made this decision different from previous decisions. In particular, for the first time, we have specifically addressed our overall revenue decision and its contribution to the achievement of the NEO. We consider this is an appropriate change as we determine an **overall revenue allowance** (emphasis added). We do not seek to interfere in the decision a service provider will make about how and when to spend the total capex or opex allowance to run its network.*

We have serious reservations about the views expressed above by the AER. Whilst the decision to approve or refuse the annual revenue requirement for each year of the regulatory control period, as set out in the building block proposal, is a key constituent decision that the AER has to make, the NER is very clear on how this annual revenue amount is to be determined. Most importantly, it is determined by aggregating the key inputs that make up the revenue amount (building block approach) with each input having its own decision making framework and criteria.

We are concerned that the AER has incorrectly carried out its task in determining the annual revenue requirement for us as it is not free to determine 'an overall revenue allowance' but it must, under the rules, determine this total amount by reference to each of its decision on each key inputs into this amount.

The rules applicable to Ausgrid 2014-19 regulatory proposal is Chapter 6 of the National Electricity Rules, as amended by clause 11.56.4 which provide certain exceptions to the operation of Chapter 6. More importantly, clause 11.56.4 governs the making of a

[24] AER draft decision, Overview, p.11

[25] Clause 6.3.1 of Chapter 6 of the NER

distribution determination for the subsequent regulatory period (i.e. 2015-19) except as otherwise specified in that clause. The exceptions concerned mainly with the true up for the placeholder revenue for the transitional year.

Chapter 6 sets out the constituent decisions that a distribution determination is predicated upon. Of note is the requirement for the AER to either approve or refuse to approve the annual revenue requirement as set out in the building block proposal. Clause 6.12.3 deals with the AER's discretion in making distribution determination. It states, the AER must approve the total annual revenue requirement for a regulatory control period and for each year of the regulatory control period as set out in the DNSP's building block proposal if the AER is satisfied that those amounts:

> *…have been properly calculated using the PTRM on the basis of the amounts calculated, determined or forecast in accordance with the requirements of part C of Chapter 6.*

Part C deals with building block determination for standard control services. Clause 6.4.3 of Part C deals with the calculation of the annual revenue requirement. This clause states that the annual revenue requirement for each year must be determined using the building block approach. The building block approach has a number of elements: including forecast opex, capex and allowed rate of return. Each of the AER's decisions have a specific decision making criteria. For instance the AER's decisions for forecast opex and capex are set out in clause 6.5.6 and 6.5.7 of the rules.

Also relevant are the matters under 6.10.1 and 6.11.1 which requires the AER must have regard to the regulatory proposal, written submission and any analysis. These requirements apply to all aspects of the AER's distribution determination. Also relevant is 6.12.2(a)(4) requires the AER must set out the basis and rationale of the determination including:

> *Reasons for the making of any decisions, the giving or withholding of any approvals, and the exercise of any discretion as referred to in this Chapter 6, for the purpose of the determination, such reasons being expressed by reference to the requirements relating to such decisions, approvals or discretion as are contained in this Chapter.*

The effects of these clauses are that:

- The AER must determine the annual revenue requirement for Ausgrid for each year of the 2014-19 period based on the building block approach. The building block contains a number of elements.
- The AER must make a separate determination for each of these elements in accordance with the relevant decision making criteria specified in the rules for each element.
- The AER must explain its decision for each element with reference to the rules requirements for each decision.

Concerns with the AER's constituent decisions for opex and rate of return

The AER's draft distribution determination is comprised of a number of constituent decisions. We are concerned that the AER has not properly carried out its task under the decision making criteria for forecast opex, and the allowed overall rate of return.

Specifically, we have grave concerns on the AER's decision on forecast opex and allowed rate of return with regard to:

- The validity of the AER's draft decision with reference to the requirements of the NER; and
- The substance and merits of such decisions.

We address these issues further in the relevant opex and rate of return chapters. In the sections below, we set out our high level concerns with the AER's decisions. In particular, we outline the substantive effect of the 2012 rule change. This is critical as the AER has contended that recent rule changes afforded it more discretion and 'make the basis of this decisions fundamentally different from previous decisions'.

Forecast opex

The AER has stated that the changes to the NEL and NER have provided it with greater discretion in terms of its decision making. We consider that this has led the AER to make a decision which has not properly addressed itself to the requirements of the operating criteria, with respect to the opex factors.

In particular, the AER has placed unreasonable weight on its benchmarking results, which is only one factor of 11 specified factors under the rules. Moreover, the rules allows the AER to consider any other factors it considers relevant and has notified the DNSPs (clause 6.5.6(e)(12)). The AER sought to rely to this factor to add two additional aspects of its benchmarking analysis. Benchmarking is a specific opex factor (clause 6.5.6(e)(4)). This supports our contention that the AER's decision on forecast opex relies exclusively on benchmarking to both reject our proposed forecast opex and as the basis for its substituted opex.

The AER has done so without meaningfully considering other opex factors that should have had significant weight in its decision such as actual and past expenditure, and the incentive mechanisms that applied. Had the AER considered these factors it may have concluded that our opex in the 2012-13 base year was significantly better than the determination the AER had set in the 2009-14 determination.

By taking this approach the AER has effectively disregarded its 2009-14 distribution determination which set the efficient forecast opex for Ausgrid for the 2009-14 and the incentive scheme that it applied to Ausgrid for this period. It is not sound regulatory practice and therefore is not reasonable for the AER to effectively ignore its own 2009-14 decision and retrospectively re-determine its view of an efficient level of opex, when it has adopted a base year roll forward approach to determining the efficient level of opex. Adopting a base year approach to determining opex, creates an unavoidable link between the 2009 to 2014 decision and the current decision, particularly given the formulaic approach the AER has adopted when applying the base year opex.

The 2009-14 determination made by the AER was the basis upon which Ausgrid set its business objectives, operations and management decisions for this period. Ausgrid failed to comprehend how an actual opex outturn that is below the efficient opex allowance determined under a valid AER's distribution determination can subsequently be found to be inefficient, as the AER found in its draft decision.

We consider that the AER has placed an unreasonable weight on benchmarking analysis due to incorrectly interpreting the discretion it has available under the amended rules. In order to properly understand and assess the substantive impact of the amendments to Chapter 6 of the rules with respect to the assessment of proposed forecast expenditure, it is necessary to:

- compare and contrast the applicable rule provisions before and after the rule change; and
- place the amendment to the rules in the context in which they were made, particularly the 'problems' with the existing framework that the subsequent amendments were intended to address.

The changes made to the NER in November 2012 were instigated by the AER. The changes proposed by the AER were sweeping, focusing on a range of substantive matters as well as procedural matters. Of the substantive changes, the AER's proposal focused on the scope of its discretion on a number of key elements of the building block framework, namely the rate of return, forecast capex and forecast opex. In its submission to the 2012 rule change, the AER submitted that the best way to resolve the issues (perceived by the AER as existing in the previous rules as hindering its ability to determine an efficient expenditure forecast) is to authorise the AER to independently determine forecast costs.

After analysing the 'problems' purported to have existed in the NER, the AEMC concluded:

- Increases in the rate of return and expenditure allowances are both significant factors contributing to rise in network charges. However, some increases in expenditure allowances have been necessary.
- On the basis of the material considered, it is not possible to conclude that the NER have constrained the AER's ability to consider and substitute NSP's expenditure forecasts and have caused inefficient increases in expenditure allowances.
- While the Chapter 6A approach to capex and opex allowances remains generally consistent with good regulatory practice, it could be enhanced in some ways, and some changes for clarification reasons should be made so that Chapter 6 and 6A of the NER better reflect this approach.

As a result, the Commission determined to make a number of changes to clarify and remove ambiguity in the NER. We consider that the AER has misconstrued the rule change in a number of respects, which are set out below.

Rate of return

The rules state that the allowed rate of return is to be determined such that it achieves the allowed rate of return objective. The objective is that the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service. There are two elements of the AER's decision on the rate of return that we consider do not meet the rules requirements. We consider that this does not enable us to meet the Revenue and Pricing Principles in the NEL.

Transition path to trailing average

We do not agree with the AER's proposed ten year transition path to the trailing average. As Ausgrid has historically issued debt on a benchmark efficient staggered portfolio basis, the AER's proposed transition would significantly under-compensate us based on current forecasts of yields on 10 year BBB corporate bonds and would not operate to minimise any difference between the return on debt and the return on debt of a benchmark efficient entity with a similar degree of risk as that which applies to Ausgrid.

The application of the AER's proposed debt transition is inconsistent with a number of the revenue and pricing principles in section 7A of the NEL. In particular, the AER's proposed transition would not, over the 2014-19 period, provide us with a reasonable opportunity to recover at least the efficient costs of debt finance, nor give rise to prices that would allow for a return commensurate with the regulatory and commercial risks involved in providing direct control network services.

The AER's proposed transition path would mean that the benchmark efficient approach for setting the allowed return of debt (the trailing average approach) would not be fully implemented for 10 years, i.e. not until the 2024-29 regulatory period. We consider that a debt transition that is not fully unwound until 1 July 2024 is not reasonable for firms that already issue debt on a staggered portfolio basis. If the AER applied its proposed transition to firms that issue on a staggered portfolio basis, it would be setting revenue allowances that are insufficient to cover forecast costs of debt for firms with efficient debt management practices.

Cost of equity

The AER has not had regard to relevant evidence and models that were submitted as part of our initial proposal when setting the allowed return on equity. This is inconsistent with clause 6.5.2(e)(1) if the NER. In addition to this, the AER's draft decision

inconsistently applied the risk free rate parameter within the CAPM by using a short term risk free rate in one part of the equation and a long term risk free rate in another part. This is in breach of clause 6.5.2(e)(3) of the rules which requires that the AER have regard must be had to any interrelationships between parameters when setting the allowed return on equity.
The AER should have had regard to the following evidence, which is relevant within the meaning of clause 6.5.2(e)(1) of the rules:

- Fama-French model based estimates of the cost of equity for the benchmark firm.
- Black CAPM based estimates of the cost of equity for the benchmark firm.
- DGM based estimates of the cost of equity for the benchmark firm.
- Empirical evidence of the low beta bias of the Sharpe-Lintner CAPM beta.

Ausgrid has considered all relevant evidence and financial models in determining our proposed return on equity of 10.15%. Our point estimate has been chosen from within a reasonable range of relevant estimates that includes a Sharpe-Lintner CAPM point estimate using long term estimates of the market risk premium (MRP) and the risk free rate, a Sharpe-Lintner CAPM point estimate using short term estimates of the risk free rate and the MRP, and outcomes from the Black CAPM, Fama-French 3 Factor Model (FFM) and DGM based estimates. Our point estimate within the range corresponds to the Sharpe-Lintner CAPM estimate of the cost of equity using an equity beta of 0.82 and long term estimates of the risk free rate and MRP.

2012 rule change

We outline the substantive effect of the 2012 rule change below.

AEMC maintained structure of existing framework

The 2012 rule change largely maintained the existing framework in the rules that were applied to making our 2009-14 determination. This included maintaining the structure of the objectives, criteria and factors.

After extensive consultation and analysis, the AEMC essentially rejected the AER's proposed changes to the framework, one that, if accepted, would allow it to unilaterally determine and impose its own forecast expenditure on the NSPs. The AEMC stated:

> *It is not possible to conclude that the NER have constrained the AER's ability to consider and substitute NSPs' expenditure forecasts and have caused inefficient increases in expenditure allowances.*
>
> *The Commission confirmed that the NER is drafted appropriately in many areas. With the exception of benchmarking, the capex and opex criteria remain valid.*
>
> *The AER proposed that the criterion relating to demand forecasts and cost inputs was less than important than the first two criterion and should be moved to the capex and opex factors. The view was taken in the draft rule determination that it would position the demand forecasts and cost inputs as objectives rather than key elements of expenditure allowances that are relevant in a range of ways. The Commission therefore remained of the view that this criterion should remain where it is.*[26]

An additional opex factor was inserted in the rules to allow the AER to consider any other factors that it considers relevant, after having notified the NSPs of this factor in writing before the submission of a revised regulatory proposal.[27]

The insertion of this 'other factor' resulted from the AER's contention that it should be able to raise any other expenditure factor prior to the submission of the revised regulatory proposal. The AEMC accepted that there may be other relevant expenditure factors that may not have been covered within the other expenditure factors in the rules and consequently allowed the amendment of the NER to include clause 6.5.6(e)(4). It is however important to note the following analysis from the AEMC when allowing this change

> *The Commission considers that the existing capex and opex factors are sufficiently broad that it should be rare that the AER would need to consider additional factors.*[28]

Role of benchmarking

The AER consider that it is sufficient to rely on benchmarking analysis to reject and substitute its determination. The AER state that:

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[26] AEMC 2012, Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Draft Rule Determination, page 109; Final Position Paper, page 89.

[27] Clause 6.5.6(e)(12).

[28] AEMC 2012, Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Draft Rule Determination, page 109; Final Position Paper, page 89.

While these general steps are consistent with our past determinations, we have adopted a significant change in how we give effect to this approach, following the major changes to the NER made in November 2012. Those changes placed significant new emphasis on the use of benchmarking in our expenditure analysis. We will now issue benchmarking reports annually and have regard to those reports. These benchmarking reports provide us with one of a number of inputs for determining the benchmark efficient costs of providing opex.

However benchmarking analysis is only one factor that the AER must have regard to. Moreover, it is only an expenditure factor, not an expenditure criterion. Its role is to help the AER assess whether the proposed forecast expenditure reasonably reflects the expenditure criteria. It neither replaces the criteria nor is the sole criterion upon which an assessment of the proposed forecast expenditure is made.

The 2012 rule change also inserted in clause 6.5.6(e)(4) the reference to 'the most recent annual benchmarking report that has been published under rule 6.27'.

At first glance, it appears that such amendment is superfluous as the need for the AER to take into account benchmarking already exists before the rule change[29]. On closer analysis of the context under which this amendment arose, it is clear that the amendment relating to the preparation and publication of an annual benchmarking report fundamentally stemmed from the need to improve information available to customer to better facilitate consumer's engagement in the regulatory process. Consequently, clause 6.27 of the NER was inserted to require the AER to prepare and publish an annual benchmarking report in reasonably plain language. This was the primary objective of this change and resulting NER clause.

The AEMC also considered that the annual benchmarking report would assist the AER in assessing a NSP's regulatory proposal. Hence, the opex objective 6.5.6(e)(4) was amended to include the reference to the annual benchmarking report[30]. It is imperative to note that these annual benchmarking reports are but only one of a suite of information that the AER needs to have regard to in making a determination on Ausgrid's forecast opex. It is not the only piece of information and certainly it does not displace the NSP's regulatory proposal.

Individual circumstances

The AER has stated that it is not obliged to look at individual circumstances[31]. The removal of the 'individual circumstances of the NSPs' from the opex criteria does not remove the need (and the obligation) for the AER to consider the circumstances of the NSPs given the requirement to accept the forecast operating expenditure that reasonably reflects the operating expenditure criteria. The criteria necessarily involve consideration of the individual circumstances of the business as recognised by the AEMC in its final position paper for the 2012 rule change.

The phrases 'in the circumstances of the DNSP' appeared in clause 6.5.6(c)(2) of the NER prior to the change. In its rule change request, the AER proposed to delete the opex criteria altogether. Explaining the rational for its proposed deletion the AER stated that:

Further, it is proposed to delete the criteria relating to the circumstances of the relevant NSP. Good benchmarking practice requires that the characteristics of the individual network be taken into account in the normalisation of the data, including matters such as network topography. However, this is different to taking into account the circumstances of the individual owner of the network. The imprecise language used in the current rules may limit the AER's ability to apply comparative analysis and benchmarking in identifying efficient cost. [32]

The AEMC agreed to remove this phrase from the opex and capex criteria in the NER. In explaining and clarifying this decision and the intended effect of the removal, the AEMC unequivocally stated that:

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. 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. 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

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[29] Clause 6.5.6(e)(4) before the 2012 rule change refers to 'benchmark operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period'.

[30] AEMC 2012, Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Draft Rule Determination, page 109; Final Rule Determination, page 108.

[31] AER draft decision, Attachment 7-54.

[32] Rule change proposal, Econonomic regulation of transmission and distribution network service providers, AER's proposed changes to the National Electricity Rules, September 2011, p. 3- 33.

> *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 objective. 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.*

It is clear from the above that the removal of the phrase from the operating criteria was to remove any ambiguity that the AER may have perceived to exist or may have attributed to the clause as it existed in the rules then. The removal does not however displace the need for the AER to consider and assess the individual circumstances of Ausgrid's in making a decision on Ausgrid's proposed forecast opex for the 2014-19 period. Something that we considered the AER failed to do. In summary:

- The opex criteria (efficient costs, costs of prudent operator and realistic expectation of demand forecast and cost inputs) still remain the test for the AER in assessing a NSP's proposed expenditure forecast. Equally, these remain the critical criteria for the AER's substituted forecast should the AER decides not to accept the NSP's forecast.
- The expenditure factors are mandatory matters/factors that the AER must have regard to in deciding whether the proposed forecast opex reasonably reflects the expenditure criteria. These factors are of course in addition to the need for the AER to have regard to the NSPs' regulatory proposal, submissions and the AER's analysis. These three matters were previously expenditure factors but have been 'elevated' to matters that the AER must have regard to in making a distribution determination as a whole rather than as specific expenditure factors.

AER must start with a DNSP's proposal

The AER contended that the rules, as they existed prior to the 2012 rule change, make it difficult for the AER to effectively review and assess expenditure proposal. The AER considers that this is because the rules allows the NSPs unfettered discretion in the methods and models that the NSPs may use to develop and support the expenditure forecast. The AER contented that such broad discretion means that the specific details of a NSP's forecasting method remain largely unknown until the submission of the regulatory proposal.

The AER proposed that the rules be amended to allow it to specify the models and/or methods that a NSP must apply to develop and support expenditure forecasts.[33] The AEMC did not accept such a change to the regulatory framework as proposed by the AER, that is, mandating a forecasting methodology. The AEMC stated:

> *The Commission accepts that responsibility for developing a NSP's proposal should remain with the NSP. This includes the development of an expenditure forecast in a manner that the NSPs view as appropriate. It is the AER's role to assess the NSP's proposal using any tools it views as appropriate.*

The AEMC, however, considered it important for the AER to receive information on how the NSP propose to develop its forecast expenditure. The AEMC amended the rules to:

- Introduce the forecast expenditure assessment guidelines into the regulatory framework. This guideline is to outline how the AER propose to assess forecast expenditure proposal. The AER, in its framework and approach for a particular NSP, will specify how it intends to apply this guideline in the upcoming distribution determination.
- Introduce the requirement that the NSPs must inform the AER of the methodology the NSPs proposes to use to prepare the forecast expenditure that forms part of its regulatory proposal.

Overall rate of return

The AER has not had proper regard to the current debt structure of the NSW DNSPs which we consider reflects an efficient approach to debt management, with the AER's approach to imposing a transition to the trailing average not providing sufficient revenues to meet the requirements of the NEL, NEO and NER. The AER has also not taken account of relevant evidence when setting its return on equity, which is inconsistent with the requirements of the rules and results in a return that does not adequately compensate equity holders and is insufficient to attract investment in infrastructure assets.

[33] AER, Directions Paper Submission, 2 May 2012, p. 12

1.3. Why our revised proposal best meets the NEL and NER requirements

As we noted in Section 1.2 we consider that the rules provide for a series of constituent decisions that, if made in accordance with the decision making criteria (having regard to inter-relationships), will provide a revenue stream that gives effect to the NEO. That is, the resultant revenue will promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, safety, reliability and security of supply of electricity; and the reliability, safety and security of the national electricity system.

In our initial proposal we provided information to enable the AER to be satisfied with our proposals for each constituent decision in accordance with the decision making criteria in the rules. Our revised proposal has looked carefully at the AER's draft determination and its reasons for it to assess whether revisions are necessary in light of the AER's findings. In many cases, we have accepted that the AER has identified a valid issue, or has developed a reasonable alternative. In these cases, we have revised our proposal to address the change required by the AER. In other cases, we consider the AER's decision making has not been appropriate, or that the substantive issue raised can be addressed without revisions to our proposal.

The purpose of this section is to demonstrate that our proposals for each of these constituent decisions better satisfy the decision making criteria relative to the substitutes derived by the AER. In this way, we consider that the resultant revenue better meets the NEO.

Despite the revisions we have made, we note that our revised proposal significantly differs to the AER's draft decision in a number of material respects. Most notably, the AER's draft determination provides a revenue allowance for our standard control services that is 36% lower than our revised proposal. This in turn is based on three differences in our constituent decisions:

- Our revised capex is 48% higher than the AER's draft determination.
- Our revised opex is 56% higher than the AER's determination.
- Our revised allowed rate of return is 8.85% compared to the AER's draft determination of 7.15%.

In contrast the AER's draft decision did not address the relevant aspects of the NEO in terms of safety, reliability, quality and security of services. We believe that the AER did not address itself to the capex and opex criteria when making its decision, specifically it has not addressed how it substitute forecasts will enable Ausgrid to meet the operating and capital expenditure criteria. Further the AER's decision on an overall revenue requirement that best satisfies the NEO did not clearly identify the safety and reliability implications inherent in providing a significantly lower revenue amount.

In this section, we demonstrate how our revised capex and opex contributes to achieving the safety and reliability of services. We demonstrate that the AER's revenue allowance would not be sufficient to achieve safe and reliable network services in our circumstances. This is set out in Section 1.3.1 and 1.3.2 respectively. To this extent we have provided a statement at confidential Attachment 1.02 from our Chief Operating Officer which sets out why the expenditure and proposed allowed rate of return is required to meet the NEO.

Further, we would also not have the financial sustainability to fund our activities, or absorb losses from undertaking unfunded expenditure required to sustain the safety and reliability of the network.

Safety issues

Public and worker safety

Modern society places a high value on the safety of its citizens. Electrical networks are inherently dangerous, and without effective risk management of the network asset, infrastructure and systems there is an increased likelihood of electrical shocks and / or electrocution, asset failure resulting in injury to people and property damage, explosions and bushfires. It is for this reason that we have an ordered priority for a safe, reliable and affordable electricity network.

We strive to continuously improve our safety standards and practices across the electrical distribution network in accordance with National Electricity Rules objectives and the expectations of the public. We prioritise safety to ensure so far as is reasonably practicable, that we do not adversely impact the safety of our workforce and the members of the public in the delivery of reliable and affordable services to our customers and the community.

The capital and operating expenditure amounts in our revised revenue proposal embodies our commitment to the prioritisation of safety. The proposal has been designed to meet Ausgrid's legislative obligations under the *Work Health and Safety Act 2011* (NSW) (WHS Act), in particular meeting the "primary duty of care".[34]

Ausgrid's revised proposal has used recognised risk methodologies and processes to ensure that its obligations in relation to safety are effectively satisfied including the FMECA / RCM (failure mode effects and criticality analysis / reliability centred maintenance) process and Ausgrid's Portfolio Investment Plan (PIP) to respectively prioritise both operating and capital expenditure resources relative to risk.

These processes indicate that Ausgrid requires $6,435 million ($2013/14) in capital and operating expenditure for standard control services to safely manage and operate its business.

A failure to allow Ausgrid to recover this amount of capital and operating expenditure will lead to increased safety risks due to higher numbers of asset failures with potential fatal consequences to Ausgrid employees and the public and would lead to Ausgrid breaching its obligations under the WHS Act. The identified network asset failure modes and the foreseeable safety consequences are outlined in sections 1.2. and 1.3.

Public and employee safety implications of the AER's determination

The AER has demonstrated an alternate view to Ausgrid, particularly in relation to safety. In our opinion the AER's Draft Determination has not reasonably assessed or proposed an acceptable balance between economic costs and the risk to safety, nor has the criticality of these consequences or the potential stakeholder implications been thoroughly considered. It is also our view that the AER draft decision does not provide sufficient revenues to maintain the safety of the system consistent with achievement of the NEO.

The AER's Draft Determination did not include a safety risk assessment of the potential for increased network asset / system failures as a result of the proposed reduction in 'resources', or the extent to which these reductions would have adverse consequences to the health and safety of workers and members of the public.

The AER stated that its own 'cost modelling and detailed assessments' were used to review the businesses' base operating expenditure efficiency. These detailed assessments included a number of factors which notably excluded safety[35]. In the same communication it was stated that "Peers in other states are able to provide safe reliable services at lower overall levels of opex."

We disagree with this statement and draw the attention of the AER to recent critical electrical network failure events in other states which have had, or had the potential to, impact the lives and wellbeing of the public.

The Royal Commission into the 2009 Black Saturday fires (VBRC)[36] noted that 173 people had died in the bushfires. The Commission stated:

> *Victoria's electricity assets are ageing, and the age of the assets contributed to three of the electricity caused fires on 7 February 2009 - the Kilmore East, Coleraine and Horsham fires. Distribution businesses' 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 preventative 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.*

Similar concerns have been raised with the safety practices and risk management of Western Australian distributors. A parliamentary enquiry into wood poles[37] noted:

> *Given the potential consequences of any wooden pole failure, wooden power pole safety is, quite literally, a matter of life and death… Over the past 10 years in the south west of this state, there have been as many as 13 bush fire incidents, about which*

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[34] Work Health and Safety Act 2011 (NSW) s 19

[35] AER draft decisions, Pre-determination conference 8 December 2014 presentation

[36] 2009 Victorian Bushfires Royal Commission Final Report, July 2010 (Parliament of Victoria)

[37] Report 14 Standing Committee of Public Administration, Unassisted Failure, January 2012 (Legislative Council of Western Australian, Thirty-eighth Parliament)

subsequent investigations have suggested that faulty electricity infrastructure may have been the principal cause. This resulted in a tragic loss to the community of three of our fellow citizens. The total loss of property, wildlife and stock as a result of these incidents is not known but is unquestionably extensive.

In light of these real life examples, we are very concerned with the AER's views that Ausgrid's risk management processes are overly risk adverse[38] and that the AER is proposing that Ausgrid accept greater risks in terms of higher rates of network failure and consequently increased risks to safety, despite Ausgrid's detailed technical optimisation analysis to the contrary.

Distribution network service providers operate to a number of safety standards so that assets remain in good order and to comply with legislative requirements, in particular their health and safety obligations under the WHS Act 2011 and the Electricity Supply (Safety and Network Management) Regulation 2014 (NSW). Ausgrid is also bound to operate by its legislative obligations consistent with the National Electricity Law (NEL) and the Electricity Supply Act 1995 (NSW). Therefore resources are required to maintain assets, clear vegetation and renew deteriorating and aged assets and infrastructure commensurate with the business' assessed risk profile in order to protect human life.

For this reason, Ausgrid utilises asset related preventative and mitigative maintenance controls (resources) to reduce the likelihood and consequence of hazardous events, particularly those events that have the potential to result in loss of life. In 2000, Ausgrid introduced the Failure Mode, Effects and Criticality Analysis / Reliability Centred Maintenance (FMECA / RCM) process, to identify the tasks and activities most cost effective in managing the safety and reliability consequences of the manner in which assets fail (asset failure modes). These tasks or activities may include maintenance, replacement or redesign, or where the individual failure mode does not have an adverse impact on safety and reliability, the methodology allows the option of a 'run to end-of-life' (failure) to be adopted. The application of a quantified39 FMECA / RCM, coupled with regular reviews of the asset performance data, ensures the task periods calculated for the chosen controls deliver a reasonable balance between both cost and risk for optimal asset performance.

This means that Ausgrid utilises objectively determined pre-emptive (preventative maintenance and asset renewals) and planned corrective maintenance as preventative controls to identify and address possible failures before they occur in order to maintain a safe, reliable and sustainable network so far as is reasonably practicable (SFAIRP) in accordance with the hierarchy of controls (HoC) as shown in the diagram below. That is, foreseeable hazards should be eliminated if reasonably practicable, and if this is not possible, mitigated so far as is reasonably practicable.

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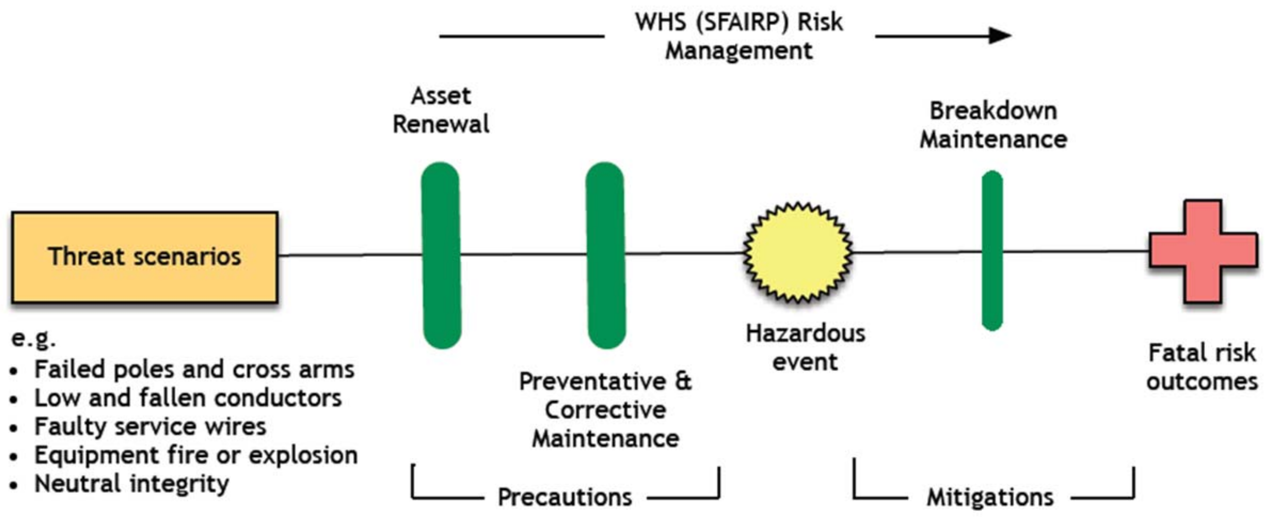
[38] AER draft decision, Overview 10

[39] Quantified via algorithms validated by the CSIRO. Ref: Validation of Specified Algorithms in MIMIR, CSIRO Mathematical and Information Sciences, Report CMIS 01/44, 26 March 2001

Figure 5 – WHS (SFAIRP) risk management concept threat-barrier diagram



Ausgrid disagrees that the AER's Draft Determination provides a revenue stream within which the business can prioritise its expenditure to adequately manage the safety risks, so far as is reasonably practicable. We consider that the magnitude of the AER proposed capital and operating expenditure reductions in the Draft Determination, coupled with the retrospective nature for which these will need to take effect, will drive an abrupt and fundamental organisational re-design, reprioritisation of programs and an increase in safety risk to our workers and members of the public beyond the limits that are acceptable.

The impact relative to Ausgrid's organisational human resources would require significant and immediate job reductions in the vicinity of 2,400 representing a 45 per cent reduction in workforce across the organisation. The scope and abruptness of the proposed reduction in a high risk industry could well create a significant human error-inducing factor on a technically specialised and experienced workforce, already implementing efficiency change management programs under the New South Wales (NSW) Government's Reform Program.

A number of Ausgrid's prioritised and successful programs are at risk of being identified as discretionary, due to the proposed reduction in operating and capital expenditure. Ausgrid's Black Spot Program will fall into this category. There is a public and private interest to reduce motor vehicle collisions and injuries associated with electricity network pole impacts.

Of the three NSW Network Businesses, Endeavour Energy has been the originator of the Black Spot Program investing more than $7 million over the past five years in the relocation of power poles. Between 1998 and 2008 there were 149 fatalities resulting from motor vehicle collisions and power poles in Endeavour's franchise area (an average of 14.9 fatalities per year). Since the inception of Endeavour's program in 2009/10, a total of 57 rectification projects have been completed. Between 2009/10 and 2013/14 we understand there have been 27 fatalities resulting from motor vehicle collisions and power poles in the Endeavour franchise area (an average of 5.4 fatalities per year). While a number of road safety factors have contributed to this improvement in Endeavour's area Ausgrid would expect, over time, to reduce the number of road fatalities through the implementation of this program. The CEO of Roads and Maritime Services has written in support of the continuation of this program.[40]

Safety risk assessment

The AER does not appear to have sought the advice of WorkCover NSW or the NSW Department of Trade and Investment as to the appropriateness of the proposed capital and operating expenditure allowed for in its Draft Determination. This is particularly surprising given the level of consultation with Energy Safe Victoria in the Victorian distribution determination 2011 – 2015[41] and given the comments in the 2009 Victorian Bushfires Royal Commission:

[40] This statement is provided as Attachment 1.18 - Letter from CEO of Roads & Maritime Services

[41] AER draft decisions on NSW Electricity Distribution Regulatory Proposals 2015-19

Protection of human life must become the priority when evaluating distribution businesses expenditure proposals. The economic regulatory regime must include mechanisms for ensuring that safety-related matters are properly reviewed so as to minimise the risk of bushfire being caused by the failure of electric assets. [42]

Ausgrid has commissioned R2A to conduct a safety risk assessment[43] to identify likely network asset / system failures that have the potential for fatal consequences which may arise from implementing the AER's proposed operating and capital expenditure in the Draft Determination.

The safety risk assessment was completed by R2A within a precautionary due diligence risk management framework consistent with the WHS Act. The approach taken by R2A has been used in a number of studies and was expressly used in the report[44] of the Powerline Bushfire Safety Taskforce, arising from the Royal Commission into the Black Saturday fires in Victoria, all of whose recommendations were adopted by the Victorian State Government.

The assessment concludes that it is foreseeable that safety risks for Ausgrid workers and the members of the public will increase from the AER's Draft Determination where it is proposed that Ausgrid's operating and capital expenditure be significantly reduced relative to recent actual expenditure levels. The R2A report states that the analysis indicates:

If Ausgrid were to operate within the constraints of the AER's draft determination, then in the short term, the number of safety incidents, especially to employees, is expected to spike……In the longer term, this analysis indicates that for the foreseeable threats to members of the public considered in this review, an increase of around 3.4 per annum in the fatality rate from network hazards would most likely occur. In addition, the likelihood of the Ausgrid network starting a catastrophic bushfire (meaning 100 fatalities and 1,000 houses lost) more than doubles as a result of increased equipment failures due to longer inspection cycles.

R2A also states that the AER appears to accept that there will be an increase in unexpected events resulting from the draft determination. The report further notes:

The AER draft determination as it stands, is in effect, directing Ausgrid to disregard Ausgrid's own determination of what Ausgrid believes is necessary to demonstrate SFAIRP under the provisions of the Work Health and Safety Act 2011.

Work Health Safety Act 2011

Primary duty of care

Under the WHS Act, the Primary Duty Holder is a 'person conducting a business or undertaking' (**PCBU**). There are a number of obligations with which a PCBU may need to comply but the primary duty of care is set out at sections 19 (1) and 19 (2) of the WHS Act.

Under this duty, the distribution network service providers must ensure so far as is reasonably practicable:

1) the health and safety of workers (which is defined to include contractors) while they are at work in the business or undertaking; and

2) that the health and safety of other persons (which includes members of the public) is not put at risk from work carried out as part of the conduct of the business or undertaking (maintaining the safety of the Network Asset / System).

The primary duty is limited by what is "reasonably practicable". This is defined under the WHS Act as that which is, or was at a particular time, reasonably able to be done in relation to ensuring health and safety, taking into account and weighing up all relevant matters.

A PCBU needs to consider what is able to be done in relation to the identified risk and then the extent to which those identified control measures are reasonable in the circumstances. However, cost, of itself is unlikely to be a sufficient justification for choosing a lower order safety control measure (or for not implementing a safety control measure) unless the cost is "grossly disproportionate to the risk".

Officer's duty

Under the WHS Act, an Officer of the PCBU must exercise due diligence to ensure that the PCBU complies with its duty or obligation under the WHS Act. Due diligence is defined to include taking reasonable steps to ensure that the PCBU has available for

[42] 2009 Victorian Bushfires Royal Commission Final Report, July 2010 (Parliament of Victoria) 4.5.1

[43] Attachment 1.13 - R2A Ausgrid Asset / System Failure Safety Risk Assessment January 2015

[44] Powerline Bushfire Safety Taskforce Final Report 30 September 2011 (in particular Appendix E)

use, and uses, appropriate resources and processes to eliminate or minimise risks to health and safety from work carried out as part of the business or undertaking.[45]

We are of the opinion that the AER as a public authority is a PCBU under the *Work Health and Safety Act 2011* (Cth) (Cth WHS Act) and, accordingly, is subject to the primary duty of care. This means that the AER is required to ensure, so far as is reasonably practicable, that the health and safety of other persons is not put at risk from work carried out as part of the conduct of the AER's undertaking, including in making Distribution Determinations.

Significantly, the recent Royal Commission into the Home Insulation Program (HIP) made a number of recommendations designed to avoid future systemic failures and on the issue of 'risk' concluded:

> *Risk cannot be abrogated – Government must recognise that as much as it might seek to do so, risk cannot be abrogated. The responsibility of Government is to care for its citizens and to exercise care and diligence to do everything reasonable to ensure citizens are not placed in danger by its actions, particularly risk of death and serious injury.*[46]

Impact of AER draft determination on WHS obligations

We are of the opinion that if the AER is aware of the safety impacts of the proposed operating and capital expenditure allowed for in the Draft Determination and it makes its Final Determination allowing for these same levels irrespective of these safety impacts, it will be in breach of its primary duty of care under the Cth WHS Act.[47]

Based on our consideration of all factors, we are also of the opinion that the proposed operating and capital expenditure allowed for in the Draft Determination would significantly diminish Ausgrid's capacity to complying with its obligations under the WHS Act.

It is also Ausgrid's view that the AER's final determinations, if it allows for similar operating and capital expenditure levels provided for in the Draft Determination, would impact Ausgrid's officers ability to comply with their personal duties under the WHS Act.[48]

Implications for insurance arrangements

Endeavour Energy, Ausgrid and Essential Energy have jointly insured "common risks" for a number of years including bushfire liability. The bushfire risks are insured under a General Liability insurance policy. A key platform for our ability to obtain cost effective insurance for this catastrophic risk is the prudent risk management practices we employ, particularly in relation to vegetation management and the use of LIDAR to identify vegetation encroachment and asset maintenance priorities.

Aon Risk Solutions was engaged to provide confidential advice on potential implications to insurance arrangements arising from a reduction in preventative asset management particularly vegetation management expenditure. A summary of Aon's advice follows[49]:

> *If underwriters become exposed to bushfire losses arising from insured contingencies occurring across Australia or internationally, say from increased claims arising from a poor bushfire or wildfire season, then market conditions could rapidly deteriorate.*
>
> *In such circumstances, and given the past positive differentiation that NNSW has effectively conveyed to markets demonstrated through effective and prudent risk management regimes including vegetation management initiatives, faced with a more exposed risk profile the NNSW insurers could seek other opportunities in utilisation of their capacities and simply walk-away.*
>
> *This holds the potential to leave NNSW in an untenable, effectively partially or even largely uninsured position at some point over the course of the next 5 years.*
>
> *Based on the findings, analysis and considerations contained within this Report, Aon estimates that under current insurance market conditions and without further losses from bushfire liability accruing to the specialist insurance market, potentially estimated and unverified composite premium costs ...... representing an increase of up to c.125% over the current 2014/15 insurance position.*

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[45] Work Health and Safety Act 2011(NSW), s. 27(5)(c)

[46] Ian Hanger, Report of the Royal Commission into the Home Insulation Program (Commonwealth of Australia, 2014) [1.1.17].

[47] Work Health and Safety Act 2011 (Cth), s. 19

[48] Work Health and Safety Act 2011 (Cth), s. 27

[49] Attachment 1.14 - AON: Insurance Advice Report - Insurance costs and coverage impacts arising from cuts in vegetation management expenditure for the 2014-2019 regulatory period (CONFIDENTIAL)

During the 2014/15 renewal we evidenced withdrawal of a number of global underwriters for Australian bushfire liability insurance. This followed the withdrawal of participating US underwriters in 2012.

If underwriters perceive that there is a lessening of our prudent asset management practices including vegetation management then there is a strong likelihood that we will not be able to obtain effective cover for our bushfire risks potentially exposing NNSW to a level of uninsured bushfire risk.

Environmental implications

The proposed reduction in capital and operating expenditure required to maintain Ausgrid's current electricity network would result in a similar reduction in the operation and maintenance of associated systems and controls that prevent and mitigate environmental impacts.

These controls include programs such as contaminated site assessment; oil containment installation and maintenance; environmental civil works (for example, material bays, wash bays, oil storage facilities); fluid filled cable maintenance and replacement; washbay monitoring and maintenance; water treatment plant monitoring and maintenance; and PCB removal programs. The consequences of not maintaining these controls would be much more significant and are outlined in Attachment 1.15 and are addressed in the Chief Operating Officer's statement (confidential Attachment 1.02).

Reliability issues

Supply Reliability

Our initial proposals focused on meeting the long term objectives of our customers in terms of safety, reliability and price. The reliability aspects of these objectives are determined relative to our past reliability performance, the results of our customer engagement regarding customers' reliability expectations and our specific obligations under Schedules 2 & 3 of the NSW Design and Reliability Performance Licence Conditions, 2014.

The previous section on safety implications has discussed our approach to safety and our considered approach to preparation of our capital and operating programs with the required outcomes in mind. A very similar approach has been adopted in terms of meeting reliability objectives, with many planned activities inherently fulfilling both safety and reliability objectives concurrently. One fact which the AER have not commented upon in their draft determination is that the majority of network events which result in a reliability impact also provide the opportunity for a safety incident if not adequately prevented or contained. Therefore, removing the possibility of a failure addresses both safety and reliability.

Similarly to safety, the business has used widely recognised risk based methodologies and processes, including Failure Mode Effect & Criticality Analysis / Reliably Centred Maintenance (FMECA/RCM) to develop the programs which underpin the expenditure forecast put forward to the AER in our draft determination. These processes indicate that the expenditure forecasts put forward in our initial proposals, now updated in our revised proposals, are required to manage our network with the required levels of safety & reliability.

In parallel with the safety implications identified above, a failure to allow us to recover the cost of the programs put forward in our proposal will lead to poor reliability due to increased risk of asset failure, longer response times during emergencies such as major storms or fires and potential failure to meet our NSW licence obligations for reliability.

Implications of AER Draft Decision

As noted elsewhere in our revised proposal, in their draft determination the AER has formed a view, based primarily on high level benchmarking and/or modelling, that the NSW electricity distributor's forecasts did not meet the objectives of the NER. As a result the AER have rejected those forecasts and proposed the substitution of significantly lower alternative forecasts, with reductions on the order of 20-40% to both capex and opex. We do not believe that, in developing these alternative forecasts, the AER had due regard to the reliability (and safety) risk impacts. If we were to only spend within the limits indicated by the AER's draft determination a significant worsening of reliability outcomes would result.

In considering the implications of the AER's draft determination we sought the advice of Jacobs Group Australia in two areas – engineering prudency and reliability impacts. (Attachments 1.16 & 1.01)

In terms of consideration of overall risks resulting from the AER's draft determinations Jacobs noted:

> *In our opinion, the AER does not appear to have apposite consideration of the impact that the revised expenditure levels have on the risk exposure of the NSW DNSPs.*[50]

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[50] Attachment 1.16 - Jacobs - System Capex and Maintenance Prudency Assessment, p.2

With regard to reliability impacts Jacobs commented that:

> *…it is likely that the current levels of reliability cannot be maintained in the longer term with the restricted capital works program likely to result from the proposed capex reductions.*[51]

and

> *The modelling demonstrates that there will be a significant impact as a result of the reduction in maintenance expenditure, particularly over a 10 year period*[52]

The Jacobs report provided as Attachment 1.16 considered that further commentaries on certain issues in Ausgrid's revised proposal would be of benefit. We have provided a response to these matters raised by Jacobs in Attachment 1.17.

The reductions proposed by the AER, if implemented, would have impacts on the following areas:

- ***Inspections & Maintenance*** – reduced capacity for inspections and maintenance, leading to extensions of maintenance inspection cycles away from optimal FMECA/RCM identified maintenance intervals, therefore resulting in higher failure rates. In their System Capex and Maintenance Prudency report, Jacobs observed that:

> *The FMECA/RCM method analyses a variety of factors to provide a transparent view of the risks associated with different scenarios. As a result, informed decisions can be made as to the optimised inspection and maintenance regimes, considering cost, safety and reliability. In quantifying risk the tool analyses a breadth of direct and indirect costs in conjunction with probabilities and consequence costs. In Jacobs view significant reductions to system opex would disrupt the optimised programmes, which, while potentially reducing opex in the short term, would lead to higher overall costs over the medium to longer term. This would not be a prudent outcome for the NSW DNSPs.*[53]

Emergency Response – reduced capacity to respond to network faults would result from staff reductions necessary to meet expenditure forecasts set out in the draft determination. This would lead to longer fault response & restoration times, particularly during severe weather, or fires when there are high numbers of customers affect by faults ("high SAIDI days").

Capital Programs – our overall capital program is designed to support the continued safe and reliable performance of our network as assets decline in performance towards the end of their life and as peak demand on the network grows over time. Cuts such as those proposed by the AER compromise our ability to replace those assets with deteriorated performance and to support growth in maximum demand, resulting in a progressive worsening of reliability outcomes over time.

Compliance Capex – there is a small component of capex in our program, targeted at specifically addressing those parts of the network which fail to comply with Schedule 3 of the NSW Design & Reliability Performance Licence Conditions, setting out individual feeder performance requirements. The AER disallowed this expenditure in their draft determinations.

Reliability Impact Assessment

Jacobs examined the above factors, including modelling of the impacts of maintenance reductions and the longer response times resulting from the AER draft determination if it was implemented.

Jacobs modelled the impact on SAIDI of longer maintenance intervals and therefore higher failure rates based on FMECA RCM analysis undertaken across the three NNSW businesses. They then modelled the further impact on SAIDI (& CAIDI) of longer response time due to projected reductions in staff numbers as a result of the AER draft determination. Impacts on response times were confined to the approximately 10% of days when the number of outages on the network was large enough that resources to respond to faults would be constrained. On the remaining 90% of days it was assumed that staffing reductions had no impact on response times. Resource availability for both routine inspections/maintenance and emergency response was determined by applying the AER's reductions consistently across all opex.

In their report Jacobs noted that, in relation to reliability:

> *The modelling demonstrates that there will be a significant impact as a result of the reduction in maintenance expenditure, particularly over a 10 year period.*[54]

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[51] Attachment 1.16 - Jacobs - System Capex and Maintenance Prudency Assessment, p.10

[52] Attachment 1.16 - Jacobs - System Capex and Maintenance Prudency Assessment, p.3

[53] Attachment 1.16 - Jacobs - System Capex and Maintenance Prudency Assessment, p.47.

[54] Attachment 1.01 - Jacobs - Reliability Impact Assessment, p.3

As there were more potential sources of unreliability which were discussed but not quantified (including repex impacts), given the timeframe available, Jacobs also noted that

> *For the various reasons discussed, it is believed that this analysis of the impact of the Draft Decision underestimates the negative impact (increased frequency) of the impact of outages on the network.*[55]

Jacobs found that Ausgrid's SAIFI would increase by 7.3% between the base year of 2014/15 and 2020, with SAIDI worsening by 25% over the same period.[56]. They also found that by 2025 SAIFI would worsen by 14.7% and SAIDI by 33.6%.

While Jacobs did not model the overall cuts to system capex, they did discuss the drivers for capital investment. They discussed the fact that not committing repex early enough can result in asset failure with consequences including loss of supply, injury or damage. They noted that, if not committed in time augex can also result in negative reliability consequences. Overall Jacob's view was that:

> …*it is likely that the current levels of reliability cannot be maintained in the longer term with the restricted capital works program likely to result from the proposed capex reductions.*[57]

Impact on Licence Compliance & STPIS

In our initial proposal we proposed reliability capex to ensure compliance with reliability performance targets set out in jurisdictional licence conditions, in particular for the worst performing parts of our network.

In its draft decision the AER has rejected the entire reliability program, expressing a view that our proposal did not clearly indicate the basis for, and amount of, expenditure for compliance, that it appeared the proposed amount included capex to avoid penalties under STPIS and that it was unclear whether the expenditure had been included in the AER's analysis of other capex categories.

Matters of allocation are addressed and clarified in the body of our revised proposal. With those matters addressed, reliability compliance capex ought to be allowed by the AER so as to meet jurisdictional obligations, a clear objective of the NER.

The AER's draft determination outcome, if implemented, would not allow Ausgrid to maintain reliability at current levels as we cannot fund investment through avoided STPIS costs. We agree that the STPIS should fund overall reliability improvements which are separate to regulatory obligations. However, our proposal sought to maintain compliance with regulatory obligations and should be allowed.

On this matter Jacobs noted:

> *Specific cuts to reliability capex will prejudice NNSW's ability to meet Schedule 2, 3 and 5 of licence conditions even if not making a large impact on STPIS. Reduction of programmes targeting poorly performing feeders will have a direct negative impact on supply reliability. However, due to the small proportion of these programs within the overall capital program and also due to the focus of these programs on individual poorly performing feeders, rather than overall system reliability, the STPIS will not generate savings or penalties equivalent to the cost of the works. Therefore, these programs must be funded in addition to any STPIS benefits/penalty.*[58]

We have responded to the Service Target performance Incentive Scheme in Chapter 3 of our proposal. However, we note that using the analysis referred to above, Jacobs' further modelling of STPIS impacts indicated that assymetrical STPIS penalties from 0.85%, rising to 1.39%[59] over the regulatory determination period, would result from the AER's draft determination if implemented. It must be noted that the reliability impacts and therefore STPIS penalty estimates are conservative and should not be taken as an alternative STPIS proposal. They serve only to provide confirmation that the implications of the AER's draft determination are material.

Given this asymmetric outcome, a STPIS would be inapproriate if the AER's draft determination was to be implemented. We would only support a STPIS if our revised capital and operating programs were accepted in the AER's final determination.

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[55] Attachment 1.01 - Jacobs - Reliability Impact Assessment, p.14

[56] Attachment 1.01 - Jacobs - Reliability Impact Assessment, p.4

[57] Attachment 1.01 - Jacobs - Reliability Impact Assessment, p.10

[58] Attachment 1.01 - Jacobs - Reliability Impact Assessment, p.9

[59] Attachment 1.01 - Jacobs - Reliability Impact Assessment, p. 22

Financeability implications of the AER's decision

The AER's draft decision made significant reductions to Ausgrid's proposed revenue allowances over the 2014-19 regulatory period. This was the result of severe cuts to proposed levels of capex, opex, and the allowed rate of return.

The AER's draft decision implicitly assumed that it will be possible to maintain a safe, secure and reliable network with the revenue allowance set out in its draft decision. As demonstrated in this revised proposal, the safety, security and reliability of Ausgrid's network will only be maintained with the level of opex and capex set out in this revised proposal.

If the AER's draft decision on Ausgrid's allowed revenues over 2014-19 was applied in a final determination, Ausgrid would still need to spend capex and opex in line with this revised proposal to avoid exposing the network to an unacceptable level of safety, security and reliability risks. The safety and reliability consequences of not investing at the levels set out in this revised proposal are addressed in the chapters 1, 6 and 7. In addition, Ausgrid would still be required to meet wages costs, contractual obligations (such as vegetation management, IT and fleet costs) and interest costs on its accumulated debt portfolio (which has been managed on a benchmark efficient staggered portfolio basis).

Therefore, if applied in a final determination, the AER's draft decision on allowed revenues would not enable Ausgrid to recover revenues sufficient to cover its benchmark efficient costs, thus causing a material deterioration to Ausgrid's financial sustainability. Providing insufficient revenues to recover Ausgrid's efficient costs does not meet the requirements of the revenue and pricing principles in the NEL, the NEO or the rules.

We have received advice from Professor David Newbery, an internationally recognised expert on economic regulation and reform of network industries and the transport sector, which suggests that regulatory best practice is to have regard to the impact on a DNSP's credit rating as a result of changes to opex allowances. In regards to the appropriate revenue and expenditure allowance for opex, Professor Newbery noted in his report provided as Attachment 1.07:

> *I consider it unlikely that such a large reduction, in such a short space of time, to the NSW DNSPs' allowances would not impact on their ability to maintain a reliable and safe network without negatively impacting on their ongoing financeability and viability of the companies as economic entities. If the P0 reduction prejudices cash flow, then commercial credit rating agencies would likely downgrade the credit status of the companies, which would raise their WACC and possibly have a greater impact in raising total costs than the possible incentive effect might have on opex.*
>
> *…*
>
> *"International precedent indicates that when regulators have identified large inefficiencies they have used regulatory judgment to ensure that a feasible and sustainable price path is set that does not prejudice the companies' credit standings and WACC". (p 15)*

Professor Newbery also noted:

> *"It is often the case that regulators are required to take into account both the interests of consumers and the ongoing financeability of an efficient regulated company. If a regulator were to set either an unrealistic or unachievable efficiency target for regulated companies then both of these aims may be put at risk." (p.27)*
>
> ***"If there is a material error in the application of the building blocks then at the extreme a regulated company would face difficulties in raising finance to continue its operations. Therefore, the quality, reliability, safety and security of the electricity distribution system would be called into questions as the service providers would need to prioritise or reduce its services."*** *[emphasis added]*

Ausgrid has engaged Standard and Poors (S&P) to assess the financial impact of the AER's draft determination by examining the revenues contained in the AER's draft determination combined with the capital, operating and interest costs as set out in this revised proposal. The confidential S&P report, provided as Attachment 1.11, outlines that Ausgrid's credit rating under these criteria would fall well short of the AER's benchmark credit rating of BBB+, and would result in a credit downgrade to sub investment grade.

As discussed in confidential Attachment 1.12 from UBS, Ausgrid would face difficulties when trying to raise debt finance with a credit rating that is sub investment grade. The pricing of sub investment grade bonds in the Australian market results in sub-investment grade companies facing a significantly higher cost of debt than BBB, or BBB+ rated firms. UBS's analysis also suggests that there is very limited liquidity for such bonds in the Australian market. These factors would mean that a credit rating downgrade would significantly impair Ausgrid's financial sustainability.

UBS suggests that Ausgrid would not be able to fund their debt requirements nor fix their cost of debt on a benchmark efficient basis unless rated BBB+ or higher. A rating less than BBB+ would result in higher cost of debt, restrictive covenants, less liquidity and higher hedging costs.

Assuming no change in financial forecasts (revenue at the level set by the AER in its draft decision, opex or capex set at the level forecast by Ausgrid in its revised proposal), each business will require a significant reduction in debt in order to remain financially viable over the forecast period. A change in the capital structure from 60% debt and 40% equity to a structure with lower debt would see Ausgrid deviate materially from the credit metrics of a benchmark efficient entity as defined by the AER. Currently Ausgrid enjoys an investment grade standalone credit rating and its debt /equity structure is aligned to the AER's efficient benchmarked capital structure. The draft decision in one action moves Ausgrid significantly away from the benchmark efficient capital structure and directly results in the most significant downgrade ever faced by the organisation moving it from investment grade credit rating to a sub investment grade credit rating.

To move to a significantly lower debt structure would require a material equity injection, which would not be a viable proposition for investors who would be asked to commit new funds to an operation generating low or negative equity returns. A significant equity injection would be required to replace most of the existing debt, and equity naturally carries a higher risk than debt so procuring equity for an organisation where equity has little or no prospect of a return on investment for some years would be extremely challenging. The likely operational outcome for the business as Professor Newbery sets out above would be severe, with debt and equity capital providers requiring significant cutbacks to operating and capital programs in order to generate positive returns at some point in the future. This would in turn compromise the safety, security and reliability of the network service.

These outcomes are severe, but highly likely if the AER draft determination becomes a final determination and are certainly not in the interest of consumers as required by the NEO. The interests of consumers are served where regulatory decisions preserve the incentives for debt and equity capital providers to continue to invest in and support network service providers to provide a reliable, secure and safe service to consumers. In its draft determination the AER directly provides dis-incentives to debt and equity investors in network service businesses to provide safe, secure and reliable services to consumers.

Clearly, the credit assessment outcome arising from the AER's draft decision is unsustainable and would have serious and adverse impact on Ausgrid's financial sustainability. Ausgrid's revised proposal would provide sufficient revenues to facilitate a financially sustainable business while the AER's draft determination would not.

2. Our customers

Summary

Ausgrid made a genuine and clear commitment to improve the way we engage with our customers as part of our consumer engagement strategy and our regulatory proposals.

This includes a broad range of engagement activities and results that were detailed in our regulatory proposals and made publicly available. We welcome comments from the AER, Consumer Challenge Panel (CCP) and other stakeholders that acknowledge the contribution of this work and where it can be genuinely improved.

We have already taken steps to improve many of these processes and activities to ensure the results are embedded in our business operations and decision making.

We endorse comments from the AER in its draft determination[60] that also clearly acknowledge the challenges in adopting its consumer engagement guideline for network service providers as part of our regulatory proposals. The guideline was not published until November 2013, two months before we submitted our transitional regulatory proposal and six months before we submitted our initial regulatory proposal to the AER.

However, we do not accept conclusions from the AER that our proposal fails to reflect consumer concerns and views. In particular, we find it incongruous that the AER commends our consumer engagement activity and laments the inadequate notice provided by the late publication of its consumer engagement guideline and yet dismisses our findings, without providing any solid evidence to support its alternative conclusions.

Ausgrid maintains that the results from our broad engagement do reflect consumer views and concerns as stated in our regulatory proposal; that is:

- ensuring that safety is maintained and improved;
- maintaining the reliability of the network; and
- keeping further network price increases to below the cost of living.

These key outcomes from our proposals have been confirmed in further engagement conducted with customers and stakeholders after the submission of our regulatory proposal. This includes additional willingness to pay research using choice modelling methods.

We cannot find credible evidence in the AER's Draft Determination or submissions to our regulatory proposal to challenge these key findings of our consumer engagement. In particular, there has been no research conducted across our customer base to support the view that most customers would accept lower reliability or service standards as a trade-off for price reductions as stated in the AER's Draft Determination. This includes customers' willingness to accept compensation payments for longer or more frequent power outages.

We do not accept that it is reasonable for the AER to use anecdotal evidence put forward by the Consumer Challenge Panel as a foundation for its decisions.[61]

In summary, in its draft determination the AER:

- Rejected our consumer engagement findings without any foundation and criticised our compliance with its consumer engagement guideline, despite endorsing our increasing engagement activity;
- Used these points as a factor in rejecting our expenditure forecasts and developing a substitute amount; and
- Cited alternative customer priorities and concerns, but failed to provide any solid base of evidence.

[60] AER Draft decision Ausgrid distribution determination 2015-16 to 2018-19 Overview, p. 68

[61] CCP1 Submission re NSW DNSP regulatory proposals 2014-19, p.12

Ausgrid believes that based on the information we have provided throughout the determination process; and the time available from the publication of the final Consumer Engagement Guideline, the AER has formed an unreasonable view. We developed a Consumer Engagement Strategy that was endorsed by the Ausgrid Executive Leadership Team. We completed a broad and extensive range of engagement with consumers prior to the lodgement of our regulatory proposals and considered those views in our proposals.

Ausgrid's regulatory proposal and revised proposal tested consumers' views, particularly through two separate willingness to pay research programs, and as such we can reaffirm that our revised proposal will deliver outcomes that are consistent with the NEO and in the long term interest of consumers.

Consumer engagement activity

The Ausgrid Executive Leadership Team formally endorsed our Consumer Engagement Strategy in December 2013, following the publication of the AER's Consumer Engagement Guideline for Network Service Providers in November 2013.

Prior to that, our Executive Leadership Team and Board considered and endorsed our high level approach to customer engagement using five levels of engagement activity. This includes:

- Undertaking customer research;
- Engagement with unique stakeholders via various channels by each business;
- Engagement with common stakeholders via joint presentations by businesses and Networks NSW;
- Analysis of the existing business as usual engagement activities and information; and
- Undertaking an innovative joint Facebook campaign.

This was the most appropriate approach to provide insights into consumer preferences to balance the requirements of the AEMC rule change with regard to consumer engagement with the late publication of the AER's Consumer Engagement Guideline in November 2013.

Members of the AER's Consumer Challenge Panel (NSW Sub Panel 1) often refer to the engagement approaches embedded in the regulatory system in the United Kingdom as reference point for Australian distribution businesses. In its submission in particular the CCP referred to the approach of Western Power Distribution (WPD) as an example for Ausgrid to follow. Ausgrid has been in discussion with WPD in regard to its engagement strategy as part of our plans to develop and improve our own strategies. We note that WPD has built up its customer engagement plans over four years. Ausgrid was not afforded this amount of time to develop and implement its engagement strategies; rather it appears we were expected to reach this same level of mature engagement over a period of six months.

Nonetheless, Ausgrid's consumer engagement strategy is based on a set of principles, objectives and processes that are consistent with the AER Guideline and best practice set out by the International Association of Public Participation. It includes a classification of customers and engagement strategies best suited to allow those different classes of customers to participate in engagement activity.

As part of this strategy, Ausgrid, Endeavour Energy and Essential Energy developed a joint digital strategy to maximise opportunities for consumers to engage in a meaningful way on our operations and plans (refer to Ausgrid's revised proposal Attachment 2.01). This strategy was consistent with the AER consumer engagement guideline, in particular by breaking down barriers to participation and by avoiding industry jargon and using plain English language.[62]

That joint strategy was also endorsed by the Ausgrid Executive Leadership Team and the Ausgrid Board.

Ausgrid detailed the results of its engagement activity in its regulatory proposal. This activity has been acknowledged by AER General Manager Warwick Anderson in a presentation on the AER draft determination on Monday December 8, 2014, where he commended the NSW network businesses on our "significant levels of consumer engagement".

Customer research program

Ausgrid undertook a substantial research program in June 2013 that tested consumers' willingness to pay for various services. That research included 900 telephone and online surveys with both residential and business customers as well as 80 one-on-one interviews with customers. The research included a wide variety of representative samples of our customers from a geographical perspective and included feedback from families, retirees, vulnerable customers, students, renters, owner occupiers, businesses and industry.

The research made the following key findings:

[62] AER Consumer Engagement Guideline for Network Service Providers Nov 2013, p.8.

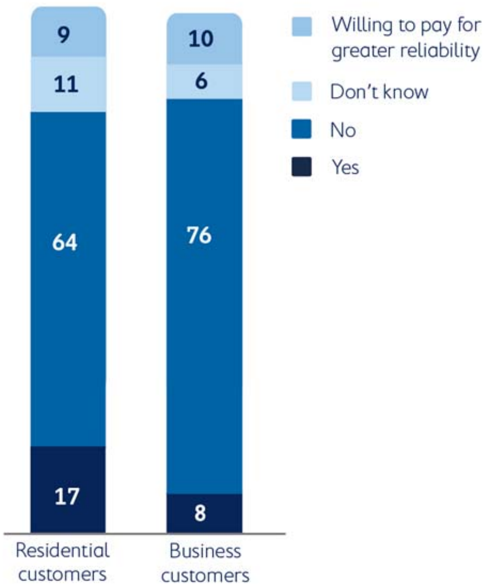
1. Safety: Customers expected that electricity was supplied in a safe manner and stated that this should be taken into account when running the electricity network. While customers generally did not want to pay more for increased safety, they definitely did not want reduced safety outcomes as a trade-off for lower prices.

> *"The qualitative participants definitely did not want to pay lower prices with associated reduced safety. They assumed this would cause more accidents for staff and workers in particular."*[63]

2. Reliability and prices: Customers were generally satisfied with current levels of reliability and in the main did not want to pay more for a higher level of reliability. Customers also did not generally want to receive lower levels of reliability in exchange for reduced prices.

Those not willing to pay more were asked if they were willing to pay less, for less reliability, and 17% of residents in total were willing to pay less, however only 8% of businesses were willing to do this.

Figure 6 – Willingness to pay less for less reliability (%)



Note: Numbers may not add due to rounding.

Q6: Would you be willing to pay less each year for a less reliable service?

Base: All respondents: Residential (n=904), Business (n=300)

Although 17% of residents who didn't want to pay more, said they were willing to pay less for a less reliable service, this needs to be balanced with the 9% of residents who said they were willing to pay more for a better service.

In the main, this supports the more holistic view that customers were most satisfied with keeping existing levels of reliability without having to pay more.

> *"There was an assumption that the power supply should be reliable and that this was absolutely expected in a country with the standard of living in Australia."*[64]

Facebook campaign

The Ausgrid, Endeavour Energy and Essential Energy joint Your Power Your Say Facebook campaign was designed to overcome natural barriers for consumers to participate in conversations about their electricity supply. The content of the campaign was designed around the research findings.

We note comments from the Public Interest Advocacy Centre on this joint campaign:

[63] Woolcott research customer engagement study July 2013, p. 21

[64] Woolcott research customer engagement study July 2013, p. 16

While PIAC welcomes this attempt by Networks NSW to engage with consumers through Facebook, social media is only one part of a broader consumer engagement puzzle.[65]

We endorse this statement. Facebook does not equal rigorous engagement on its own; however it does allow greater participation in discussions on electricity network services and the collection of qualitative feedback on views and preferences. This is valuable engagement when part of a broader strategy.

That is why we clearly set out in our engagement strategy that this campaign was one plank of a broader strategy to engage consumers in a systematic, open and accessible manner.

An analysis of the campaign found that it had reached almost 1.6 million Facebook users and had resulted in almost 62,000 interactions with consumers across a range of issues associated with their electricity supply. This included:

- Pricing
- Reliability
- Street lighting
- Electricity tariffs
- Demand management
- Drivers for network investment
- Past investment strategies
- Solar generation
- Customer communication.

Analysis and summary reports are listed on the engagement section of the Ausgrid website and attached to this revised proposal as Attachment 2.02. They provide further clear qualitative evidence of consumer support for the key outcomes of Ausgrid's regulatory proposal.

Further quantative analysis of consumer sentiment was performed on more than 1,650 mentions in relation to blackouts on Ausgrid's Facebook page, from July to December 2014 (see Attachment 2.03). It found that negative sentiment on power supply interruptions vastly increased as the number and durationof outages increased. These findings provide no support for the AER view that consumers would be content for lesser reliability in exchange for a price reduction.

Forums and presentations

Led by our CEO Vince Graham, Ausgrid joined with Endeavour Energy and Essential Energy on 11 March 2014 to present to consumer representatives on our regulatory proposal and the future challenges of the industry.

The key findings from the forum are can be found in Attachment 2.04 to this revised submission. We note that while consumer groups agreed that affordability of electricity supply was a priority, they did not put forward the view that consumers would be willing to accept compensation for more blackouts, or pay less for a less reliable service.

We note that the Public Interest Advocacy Centre's policy advisor, Oliver Derum, commented after the forum that:

While networks might stumble with engagement approaches in the early stages, just to have made this effort is recognition of the preparedness of the industry to listen and to value customers.[66]

Ausgrid also joined with other network businesses to present to electricity retailers. Our CEO and Chief Operating Officer also wrote to key stakeholders including councils, peak consumer groups, industry associations and Members of Parliament, inviting them to participate in engagement activities and encouraging active participation in both our Transitional and Regulatory Submissions, as shown in Attachment 2.05. Ausgrid's COO also led a number of briefings for regional stakeholders on our five-year plans. Ausgrid's COO also led a number of briefings for regional stakeholders on our five-year plans.

Analysis of existing data

Ausgrid analysed a range of existing data to help gain additional insights into consumer views and attitudes. This included traditional media and social media channels going back over two years, as well as correspondence, community consultation and EWON investigation reports.

For example, Ausgrid asked a social media provider to analyse online mentions of Ausgrid from 1 March 2011 to 31 October 2013 by topic to draw greater insight into the feedback it was receiving over time from customers. During this time, there were about 17,800 mentions of Ausgrid across all online sources. The sentiment of posts was also graded and analysed to understand the reasons why customers were engaging with Ausgrid via their preferred online communication channel.

[65] Public Interest Advocacy Centre Inc Moving to a new Paradigm August 2014, p.31

[66] 'Pricing and affordability centre stage at customer forum' from Everyday Endeavours March 2014

This qualitative input is in addition to our formal quantitative research. The findings of that analysis are summarised in Attachment 2.06 to this revised proposal and further shows that consumers are concerned about affordability as well as reliability. There is no evidence to show they would accept lower reliability as a trade-off for lower prices.

Findings on consumer concerns and views

There are a number of findings that Ausgrid is responding to as a result of its engagement with consumers. For example, we are designing a new engagement campaign on tree trimming in response to consumer views.

We are also developing detailed engagement plans, particularly for large customers for annual pricing submissions.

However, the consistent view put forward from consumers directly supports the key themes and outcomes of our regulatory proposal:

Maintain and improve the safety of workers and the public – New safety strategies implemented to focus on key risk areas.

Maintaining the reliability of the power supply – Capital program reduced by 47% in real terms and reliability management plan re-prioritised to maintain levels of existing reliability rather than improve supply at an additional cost.

Keeping future average price increases to less than CPI – Actual average annual prices proposed by Ausgrid for a typical residential consumer is 2.37% a year over the regulatory period.

New consumer engagement activity

We note that the AER's Consumer Engagement Guideline emphasises the importance for network businesses to commit to genuine and ongoing consumer engagement:

> *We expect service providers to recognise, understand and involve consumers on an ongoing basis, not just at the time an expenditure proposal is being prepared.*[67]

The guideline also states that:

> *Together, the principles and components seek to drive consumer engagement and a commitment to continuously improve that engagement across all business operations.*[68]

We endorse the intent of these statements as well as the AER's clear acknowledgement that meaningful consumer engagement is built up over a longer period:

> *...service providers will need some time to develop and implement robust and comprehensive engagement strategies and approaches.*[69]

Consistent with the intent of this approach, Ausgrid developed a strategic and long term approach to its engagement with customers and stakeholders, as outlined previously in this chapter.

This included our commitment to embed engagement practices into our business processes, continue to engage with consumers beyond our regulatory proposal and to review and renew our engagement strategies and activity.

We find it contradictory for the AER to clearly lay down these expectations and then ignore them when judging our customer engagement activity. This is particularly unreasonable given the late publication of its Consumer Engagement Guidelines.

We believe this is a fundamental breach of the AEMC's wishes for all parties to engage in "good faith" during this regulatory process.[70]

Community Engagement Policy

In October 2014, the Ausgrid Executive Leadership Team endorsed the delivery of a company-wide community engagement policy that is consistent with International Association of Public Participation principles. This policy is built on existing approaches to community consultation, and extended these practices systematically across the organisation. The policy is attached to this revised proposal as Attachment 2.07. The basic intent of the policy is:

> *Ensuring the community's interests and concerns are a fundamental part of planning and decision making.*[71]

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[67] AER Consumer Engagement Guideline for Network Service Providers, p. 8

[68] AER Consumer Engagement Guideline for Network Service Providers, p. 5

[69] AER Consumer Engagement Guideline for Network Service Providers, p. 12

[70] Australian Energy Market Commission National Electricity Amendment (Economic Regulation of Network Service Proivers) Rule 2012, p. 167

[71] Attachment 2.07 - Ausgrid Community Engagement System Overview, December 2014, p.1

It includes instructions for staff to inform the community of policies and procedures that may impact them, how to consider community or customer views and ways to report back on how those views were taken into account.

Stakeholder briefings

Ausgrid's Chief Operating Officer, Trevor Armstrong, presented at six major stakeholder briefing sessions from June to October 2014. Our General Managers and senior leaders also presented at the forums on our five years plans including regional spending priorities, pricing and revenue outcomes, street lighting, metering and ancillary services and consumer engagement.

The presentation included a summary of engagement methods and the key findings of engagement activity (refer to Attachment 2.08 of this revised proposal).

The locations of the forums were chosen to allow maximum participation from our major stakeholders across a range of our services and operations. More than 80 stakeholders attended the forums including representatives from consumer and welfare groups, local councils, Members of Parliament, chambers of commerce, government departments, culturally and linguistically diverse communities and large industry groups and large business. The AER and members of the Consumer Challenge Panel were invited to attend the briefing session, however they did not respond to the invitation.

The forums were designed to inform our stakeholders about the major highlights of our initial regulatory proposal and encourage participation in the regulatory process. A summary document of the forums highlighted the major issues raised by stakeholders and consumer representatives, as well as action taken by Ausgrid in response to their concerns. This summary is contained in Attachment 2.09 to our revised proposal.

The findings helped confirm the need for Ausgrid to embark on specific engagement projects such as annual pricing proposals and tree trimming programs.

We note that while electricity pricing was raised during the stakeholder briefings, there was no mention of or evidence presented of consumer's willingness to accept a less reliable service or greater risks of environmental or safety incidents as a trade-off for price reductions.

Review of Ausgrid Customer Council

As part of Ausgrid's customer service and customer engagement action plans, it was agreed to review the operation of the Ausgrid Customer Council. A scoping paper was presented and endorsed by the Customer Council and the Ausgrid Executive Leadership Team. Refer to Attachment 2.10 for more detail. The objective of the project was to:

> *…ensure that the Customer Council functions in a way to benefit both Ausgrid and its members and to align it with best practice engagement guidelines. Ultimately, the Customer Council must help serve the long term interests of consumers by helping Ausgrid management understand the preferences and views of its customers and consumers more broadly.*[72]

As part of the review, Ausgrid wrote to internal and external stakeholders, including the AER and members of the Consumer Challenge Panel asking their views on customer councils and consumer engagement.

The Ausgrid Executive Leadership Team is due to consider the recommendations from the review early in 2015.

Customer commitment statement

The Ausgrid Board has endorsed a customer commitment statement that will help staff understand their requirement to listen to and act upon customer feedback. External and Internal stakeholders were consulted on the formation of the statement.

Meetings with consumer advocates

Ausgrid notes the AER's comments in its draft determination in relation to stakeholder feedback on consumer engagement, in particular the role of the Consumer Challenge Panel:

> *We also recommend that service providers review stakeholder and Consumer Challenge Panel submissions and consult with them on how their consumer engagement strategies can be improved to provide ongoing and genuine engagement and demonstrate how stakeholder input has shaped future proposals and broader business decisions.*[73]

Ausgrid has continued to brief its Customer Council throughout the regulatory process. We have also met with consumer advocates and stakeholders including the NSW Ethnic Communities Council, NSW Council of the Ageing and the Foundation for Effective Markets and Governance on ways to improve out consumer engagement strategies and systems on an ongoing basis.

As stated here, we have systematically engaged with these important consumer stakeholders and we will continue do so. However, we note that the CCP has not responded to invitations or request from Ausgrid. Nor did it raise any aspect or shortcomings of our customer engagement with us, when we met with the panel and the AER on 20 February 2014.

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[72] Attachment 2.10 - Ausgrid Customer Council Improvement Project Scoping Paper October 2014, p.2

[73] AER Draft decision, Overview, p. 68

Annual engagement report and review of strategy

Ausgrid has committed to report back to stakeholders, customers and the community on our engagement activities via an annual engagement report. That report is currently being scoped and drafted.

We have also committed to formally review our engagement strategies, as part of our long term approach to meaningful and genuine engagement, to asses which activities are effective and where we can improve on our approach. A policy paper on this matter is due to the Ausgrid Executive Leadership Team early to mid-2015.

New research

In November 2014 Ausgrid commissioned further research into customer preferences using choice modelling methods to gain a better understanding of consumers' willingness to pay for services. A report on the preliminary findings of this research is provided as Attachment 2.11.

The discrete choice experiment conducted by Ipsos Social Research Institute presented a number of scenarios to participants reflecting different network charges and service offerings. These were then rated according to acceptability.

The results of this research validate findings from Ausgrid's previous research and engagement initiatives, which showed that while customers are concerned about affordability, the majority are not willing to trade reliability, safety and service for lower charges:

> *…the model and analysis also clearly revealed that changes in service offerings – particularly in terms of the time associated with service restoration – matter a great deal to Ausgrid customers.*[74]

Importantly, one scenario presented featured network charges based on the AER'S draft revenue determination and relative reductions in service standards due to reduced revenue.

> *This was deemed to be the most unacceptable statement of all presented, indicating that customers are unwilling to sacrifice service offerings (particularly in terms of number and duration of unplanned blackouts and service restoration times) for a large reduction in quarterly network charge*[75]*.*

The choice modelling research found that:

- While price is a driver of participants' selection of potential service offerings, the majority of customers are not prepared to sacrifice reliability and safety for lower charges.
- Price had the largest effect on likelihood to choose a potential service offering; service restoration times and pole maintenance were also key drivers.
- Service restoration times had the second largest impact on the likelihood of the selection of scenarios. Participants were much less likely to select scenarios in which the restoration of electricity took longer than the status quo.
- Decreases in pole maintenance also had a negative impact on consumers' consideration of service offerings. Any reduction in the frequency of detailed inspections (and therefore increases in the number of poles falling each year) led to a lower likelihood of selection of potential service offerings by consumers.
- These results were reinforced by the high unacceptability rating of scenario five (which had the lowest quarterly price at $141, but a reduction in the quality of all other service attributes from the status quo). Less than half the consumers surveyed found this scenario to be acceptable, and it was also deemed the most unacceptable statement of all presented, reinforcing that customers are unwilling to sacrifice quality of service (particularly in terms of number and duration of unplanned blackouts and service restoration times) for a large reduction in quarterly network charge.
- When presented with a scenario based on Ausgrid's proposed network charges and largely consistent with current service levels, around two-thirds rated the scenario as acceptable.
- The vast majority (83%) of participants were satisfied with Ausgrid's supply of electricity to their household.
- These findings provide another insight into consumer preferences; however it is one piece of evidence that requires further testing in the field. It is accepted best practice in evaluating consumer preferences to consider a range of evidence and not rely solely on research. As pointed out by Dr Gill Owen in a paper for the AER:

[74] Attachment 2.11 - Ipsos research: Willingness to pay for network services, January 2015, p. 24

[75] Attachment 2.11 - Ipsos research: Willingness to pay for network services, January 2015, p. 24

Clearly, most consumers would prefer to pay as little as possible for their energy needs, but when it comes to what should be done or not be done as a means of keeping bills down, there will be many different options and consumers will have differing views on them.[76]

And

It follows therefore, that it makes sense for the regulator to use a number of different means of consumer engagement to assess the consumer interest, so that it can "sense check" specific ideas… the regulator still retains its central role of balancing different interests and reaching judgements.[77]

These engagement activities have occurred after the submission of the Ausgrid regulatory proposal. They very clearly show that we are committed to genuine and long term engagement practices, as suggested in the AER Consumer Engagement Guidelines. The findings, wherever possible, have also been presented back to consumers, as per the AER guideline.

The views and concerns of consumers and stakeholders from this additional engagement are consistent with the views and concerns identified in our regulatory proposal.

We also took the AER guidelines on face value when it stated that:

…service providers will need some time to develop and implement robust and comprehensive engagement strategies and approaches.[78]

It is unreasonable for the AER to make this statement six months before Ausgrid's regulatory submission was due and then criticise our approach to engagement and reject our findings.

It is also perplexing that the AER makes alternative findings based on threadbare anecdotal evidence and a complete lack of robust testing of consumer views.

Role of customer engagement under the rules

A key element of the 2012 AEMC rule change was to involve customers more in the regulatory framework. The rules required that our initial proposal include a plain English overview for customers and a description of how we have engaged with electricity consumers and sought to address any relevant concerns identified as a result of that engagement.

The rules also provided a mechanism for the AER to consider customer engagement as part of its decision making for opex and capex. Assessing the extent to which the proposed expenditure addresses customers' concerns (as identified through customer engagement) is one of 11 different factors that the AER must have regard to in deciding whether to accept the proposed forecast capex and opex.

The AER released a Consumer Engagement Guideline in November 2013. Its purpose is to set out a framework for electricity and gas service providers to better engage with consumers and to set out the AER's expectations of customer engagement. Specifically, the AER notes that:

… the quality of a service provider's consumer engagement will be a factor in how we assess expenditure proposals. We will consider whether and how well a service provider considered and responded to consumer views, equipped consumers to participate in consultation, made issues tangible to consumers, and obtained a cross-section of consumer views. We will make our assessment on a case by case basis, considering whether it would have been reasonable to engage on a particular issue.[79]

On this point, we note the following statement of the AEMC in considering changes to the NER:

While the final position rules in some areas, such as the expenditure forecasting assessment guidelines, require engagement to occur in a certain way, the rules should provide for the outcomes of engagement, not the engagement itself.[80]

In November 2013, almost one year on, the AER published its Consumer Engagement Guidelines for Network Service Providers.

In response to these rule changes and guidelines, Ausgrid has initiated a broad range of consumer engagement activities, based on an engagement strategy that was endorsed by its senior leaders, to determine consumer views and concerns.

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[76] The potential role of the Consumer Challenge in energy network regulation in Australia: a think piece for the Australian Energy Regulator, Dr Gill Owen, 13 March 2013: p26

[77] The potential role of the Consumer Challenge in energy network regulation in Australia: a think piece for the Australian Energy Regulator, Dr Gill Owen, 13 March 2013: p26

[78] AER Consumer Engagement Guideline for Network Service Providers, p.12

[79] AER, Explanatory statement, Consumer engagement guideline for network service provider,s p. 22

[80] AEMC 2012, Economic Regulation of Network Service Providers, and Price and Revenue

Regulation of Gas Services, Final Position Paper, 15 November 2012, Sydney, p. 18

That activity has been extensively described in our regulatory proposals and here again in our revised proposal. We have clearly outlined the consumer concerns and views drawn from that activity and how our proposal addresses those concerns.

We consider this to be the crux of customer engagement exercises and assessing our obligations under the NER. That is, how have we taken into account customers' concerns in preparing our regulatory proposal and more precisely, in forecasting our proposed forecast capex and forecast opex.

We consider we are compliant with the AER's guideline based on the activities we conducted, as outlined in this chapter. In developing our regulatory proposal we have sought the views of customers. We have developed expenditure plans and proposed prices that address these concerns whilst balancing the need to efficiently meet our obligations and consider the long term interests of customers.

Consumer engagement and AER's decision making

It is apparent from the AER's draft determination that the views of customers have impacted the AER's decision making in two respects:

- The AER's consideration of whether our proposed capex and opex satisfied the capex and opex criteria in the rules.
- The AER's overall decision, in particular the AER has expressed a view that its distribution determination is an overall decision and must be considered as such. In this respect it considered that consumer preferences should also be reflected throughout the proposal.

AER's decision making for capex and opex constituent decisions

It is not clear to what extend the AER's decisions to reject our forecast capex and opex expenditures and to substitute the AER's own expenditure forecasts have been based on its assessment of our customer engagement process or findings. For capex, the AER stated:

> *We have had regard to the extent to which Ausgrid's proposed total forecast capex includes expenditure to address consumer concerns that have been identified by Ausgrid. On the information available to us, including submissions received from stakeholders, we have been unable to identify the extent to which Ausgrid's proposed total forecast capex includes capex that address the concerns of its consumers that it has identified.*[81]

The AER's draft decision on opex seems to place some weight on customer engagement findings presented by Ausgrid, however it is not clear whether the AER's considerations impacted its decision to reject our proposed 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 Ausgrid– particularly those expressed in the consumer-focussed overview provided as an attachment to its regulatory proposal. For example, a clear theme present in this document is that customers consider electricity prices are too high.*[82]

We consider that our initial proposal has already taken this view into account when we developed our total forecast opex and capex for the 2014-19 period. At the time we recognised the need to incorporate significant efficiencies into our forecast such that we can continue to provide the safe and reliable services valued by our customers at the lowest cost. As we discuss in Chapters 5 and 6, we have made revisions to our proposed opex and capex to reflect latest information on the efficiencies we expect to achieve in the 2014-19 period.

AER's consideration of customer preferences as part of its overall decision

While it is unclear how the AER's constituent decisions for opex and capex have incorporated the engagement activities and findings from customer engagement, the AER have been clear that customer preferences have been important in its overall draft distribution determination. The AER stated:

> *We acknowledge that Ausgrid has had a short amount of time to implement our consumer engagement guideline for network service providers. Ausgrid has undertaken engagement strategies. However, based on feedback from stakeholders, Ausgrid has not presented compelling evidence of how its proposal adequately incorporates the views and concerns of its customers. This manifests in a number of aspects. First, the number and breadth of submissions received that do not support Ausgrid's proposal as being in the long term interests of consumers. Second, the range of issues that are important to consumers and stakeholders raised in their submissions but not reflected in Ausgrid's regulatory proposal. For example, efficient demand management options instead of capex.*
>
> *Based on the submissions in response to Ausgrid's regulatory proposal and our consultation with consumers, we are not satisfied that Ausgrid's proposal adequately reflects the views of consumers. In particular, consumers have indicated that they*

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[81] AER draft decision, Attachment 6, p. 6-32.

[82] AER draft decision, Attachment 7, p. 7-23

were not offered opportunities to express preferences for service standards and costs which were backed by pricing impact information. Consumers were also concerned that Ausgrid did not disclose its intention to depart from key aspects of our rate of return guideline which was developed with extensive stakeholder consultation.[83]

The AER's statements demonstrate that it has taken a very narrow view of the long term interest of customers. Rather than assessing whether our proposed expenditure provides for a level of safety and reliability valued by customers, the AER has instead sought to focus on customers' preferences for lower prices.

This is a very simplistic lens from which to determine the long term interest of customers. It goes without saying that customers desire lower prices. However, prices simply reflect the costs of undertaking activities that provide a level of safe and reliable services. However, customer engagement activities are important to understand whether there is a more preferred balance between service levels and prices, for instance more reliability interruptions from deferring capex.

In this respect, the AER ignored material from our customer engagement activities which confirmed that our customers want us to retain our current safety and reliability levels. Instead the AER has relied on the views of customer stakeholders, who have not articulated a preference for lower safety or reliability levels in a methodical manner. We also address the issue of rate of return below.

Response to submissions and comments on our consumer engagement

The AER states in its Draft Determination that it is the number and breadth of consumer submissions that contributed to its decision to reject our proposal and how it reflects consumer views:

Ausgrid has not presented compelling evidence of how its proposal adequately incorporates the views and concerns of its customers. This manifests in a number of aspects. First, the number and breadth of submissions received that do not support Ausgrid's proposal as being in the long term interests of consumers. Second, the range of issues that are important to consumers and stakeholders raised in their submissions but not reflected in Ausgrid's regulatory proposal[84]*.*

The AER also referenced the 'unprecedented level of consumer participation' as a foundation for its decision. Ausgrid supports increasing involvement from consumers in the regulatory process, including stakeholders that represent different consumer cohorts. As we have described in this chapter, we have actively encouraged this increasing participation as part of our engagement activities.

However, we note that of the 46 submissions on our proposal, 28 of those were direct copies of the same one page letter from local councils across our network area, supporting the submission from Southern Sydney Regional Organisation of Councils (SSROC). We note that these same councils funded the work in this submission.

We also note that a further five submissions were made from electricity retailers and the industry association funded by them. Whilst able to make submissions on our proposal, we contend that these businesses do not represent consumers, nor have they demonstrated how they systematically tested consumer concerns as part of their submission.

It is not enough for the AER just to accept the making of submissions as evidence to reject Ausgrid's findings of consumer views and concerns. The submissions themselves need to present evidence to support an alternative position of consumer views and concerns. These submissions contain no such basis of fact to reject Ausgrid's extensive work to test consumer concerns.

A further three submissions were made on behalf of major energy users or electricity generators. Submissions were also made by a metering business, a demand management business and the industry association presenting the renewable energy industry.

The five remaining submissions were made by consumer or welfare groups, a group that advocates on environmental issues and the Consumer Challenge Panel set up by the AER.

There are some valuable insights in these last five submissions; however they also contain a number of shortcomings which makes it unreasonable for the AER to reject our proposal based on them. Most importantly, the submissions from the CCP and others base their findings on our consumer engagement activity and practices on the AER's Consumer Engagement Guidelines.

The consumer engagement undertaken by Ausgrid, Endeavour, Essential and ActewAGL in preparing their final regulatory proposals has been evaluated in the context of the AER Consumer Engagement Guidelines for Network Service Providers.[85]

As previously stated these guidelines were only published six months before Ausgrid's regulatory proposal was submitted. In the guideline the AER stated:

…service providers will need some time to develop and implement robust and comprehensive engagement strategies and approaches.[86]

[83] AER draft decision, Overview, p. 28

[84] AER Draft decision, Overview, p. 27

[85] CCP1 Submission re NSW DNSP regulatory proposals 2014-19, p.6

It appears to us that these submissions may have had some bearing on the AER's decisions on forecast capex and opex. To the extent that this is correct, the AER, by doing so, has ignored and contradicted its own guidelines when making its draft decisions.

Ausgrid notes that the AER also states that it received a submission from an agricultural group on our proposal and that this helped form its views on whether we had reflected consumer concerns.[87]

Ausgrid cannot find any record of this submission to its regulatory proposal.

The AER also stated that it was not satisfied that our regulatory proposal reflected the views of consumers based on its own consultation with consumers.

Based on information in its draft determination the AER conducted the following engagement activity with consumer groups or stakeholders, in addition to considering submissions and the views of the Consumer Challenge Panel:

- hosting a public forum on July 10 2014;
- holding a metering workshop on September 11, 2014; and
- meeting with the NSW Public Interest Advocacy Centre and other stakeholders to discuss their submissions in detail.

By its own standards of engagement, this level of participation to seek views on our proposal appears inadequate and could not lead to an effective judgement on whether our proposal reflects consumer views. We contrast this engagement with the level and breadth of Ausgrid's consumer engagement as detailed in our regulatory submission and this revised submission.

Consumer Challenge Panel submission

Ausgrid values the role of a Consumer Challenge Panel (CCP), however we have serious concerns about the robustness and foundation of the advice the CCP sub-panel 1 has provided to the AER.

The CCP has rejected our evidence based findings on consumer views and concerns and therefore recommended to the AER that it rejects our revenue proposal. The CCP says that it has done so based on unsourced advice and anecdotal evidence:

> *The sub-panel has received information from consumer representatives, which suggests that the consumer engagement undertaken by the NSW distribution businesses has been ineffective to date.*[88]

And:

> *Anecdotal evidence and the views of some consumer organisations suggests to the sub-panel that consumers may prefer lower prices even if that meant a greater risk of reduced reliability.*[89]

Ausgrid does not believe it is credible for the AER to accept anecdotal evidence and to reject our evidence based findings on consumer preferences. We have found no facts presented to support the consumer preferences suggested by the CPP.

We do note that there is widespread acknowledgement in submissions on our proposals that Ausgrid has embarked on extensive consumer engagement activity.

The CCP also rejects the findings of Ausgrid's research, based on the methods used in the research. It states that this is reason enough to reject our findings on consumer preferences, and seek substitute and untested views.

We considered this to be unwarranted.

The general finding from the Ausgrid research was that customers did not want to pay additional amounts to improve the reliability of their power supply. They in turn preferred to maintain their existing levels of reliability, without having to pay more. They also did not prefer worsening reliability as a trade-off for a price reduction.

Ausgrid sought an assurance from its research provider about the validity of our research. It is attached to this revised submission in Attachment 2.12. We also undertook additional research using the choice modelling techniques suggested by the CCP. As discussed previously in this chapter that research supports Ausgrid's earlier testing of consumer concerns and views.

We also note that the CCP refers Ausgrid to the survey techniques of Western Power Distribution as an example of how different survey techniques could have provided evidence to support its alternative view that consumers are willing to pay less for reduced reliability:

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[86] AER Consumer Engagement Guideline for Network Service Providers, p.12

[87] AER draft decision , Overview, p.85

[88] CCP1 Submission re NSW DNSP regulatory proposals 2014-19, p. 8

[89] CCP1 Submission re NSW DNSP regulatory proposals 2014-19, p.11 and p.12

This indicates that there is precedence for our view that consumers may prefer lower prices for reduced reliability, where the research is according to best practice.[90]

Ausgrid sought advice from WPD about these findings from the CCP (see Attachment 2.13). It stated that it was misleading for the CCP to make this claim. It explained that while about 15% of its customers voted for a deterioration of services in its research, the remainder in fact supported the maintenance or improvement of network service levels.

It went on to explain that further road testing of consumer views via qualitative assessment showed that almost all participants supported the maintenance of customer and network services at present levels, rather than a deterioration of services for a price reduction.

We did not elect for any option that led to deterioration in service. That's because from day one, stakeholders told us that their number one priority above all others was that current service standards should be, as a bare minimum, maintained.[91]

The CCP stated the WPD research conclusions were a possible source of alternative evidence to reject Ausgrid's findings on consumer concerns and preferences:

…we consider that the AER will need to take into account other evidence of the views of consumers in reaching its determinations in respect of customer willingness to pay for specific levels of reliability.[92]

We strongly contend that this finding is incorrect, and that the WPD consumer engagement program actually supports our findings on consumer views and preferences.

Public Interest Advocacy Centre (PIAC)

Ausgrid is pleased to receive and review the submission to its regulatory proposal from the Public Interest Advocacy Centre. We will address here its main findings and recommendations in regards to customer engagement.

We support PIAC's view that network businesses could submit an additional two-page summary of their regulatory proposal. We would be happy to consult with PIAC and others on how this summary could be developed.

We also support the view from PIAC that a greater attempt by both network businesses and consumer groups to engage and work collaboratively ahead of the 2018 regulatory proposals can result in more accessible and sustainable network services.

We also agree that network businesses should not shy away from constructive criticism of their operations and should produce documents with this in mind. We note that our digital strategy for consumer engagement is based on the premise that new forms of communication such as Facebook are open channels for discussion and criticism. We have encouraged this constructive criticism and used it to help inform our submission.

Lastly, we agree with PIAC that as consumer engagement becomes more sophisticated, that NSW network businesses should seek to engage with their customers about the dollar impact of, for example, reducing reliability standards. Ausgrid engaged further extensive research based on choice modelling techniques to help achieve this. We have presented this research and intend to test its main findings via further consumer workshops.

There are a number of comments from PIAC in its submission that Ausgrid not does support.

Ausgrid's plain English submission was a requirement of recent rule changes put forward by the AEMC in 2012. Ausgrid's staff wrote this document and had the document designed by a graphic artist to ensure it was easy to read and accessible.

PIAC is free to put its view that some businesses, politicians or advocates use marketing firms to create spin instead of substance in these types of documents. However, this is not the case for Ausgrid.

Our Plain English Customer Summary contains all the key highlights of our regulatory proposal, regardless of whether it portrays us in positive or negative light.

PIAC is also of the view that Ausgrid and other network businesses did not respond to concerns that low-income households were struggling to pay electricity bills and stay connected to the electricity network. Ausgrid's CEO Vince Graham has consistently and publicly expressed the view of Ausgrid that more needed to be done to reduce costs to help keep pressure off future network electricity price increases.

In particular, we have delivered the NSW Government's reform program. This is important because this program directly funds additional rebates to low income households and families struggling with electricity costs. This commitment was illustrated in 2013/14 when Ausgrid did not seek to recover the full price change it was allowed by the AER's decision for that year. The decision resulted in additional savings to customers.

[90] CCP1 Submission re NSW DNSP regulatory proposals 2014-19, p. 12

[91] Attachment 2.13 - Email from Western Power Distribution: Stakeholder Engagement Manager

[92] CCP1 Submission re NSW DNSP regulatory proposals 2014-19, p. 12

We note the success of this program in a media statement from the NSW Government that states that more than 780,000 participants had received the Low Income Household rebate. Please refer to Attachment 2.14 to this revised proposal.

In response to concerns expressed by PIAC about accessibility to our regulatory proposal, we note that we deliberately published our regulatory proposal and full list of attachments on June 2, 2014, three weeks before it was formally made available by the AER.

We also wrote to consumer groups and other stakeholders to inform them it was available, subject to being passed as a complying document by the AER. This was done to ensure stakeholders had as much time as possible to review and comment on documents.

We produced plain English summary documents of the key components of our business operations, including comparisons with past periods, to ensure customers were equipped with key information to make proper judgements on our regulatory proposal. They were all published on Facebook and have been published on our website (refer to Attachment 2.15 to this proposal).

We also make the final observation that as part of its submission PIAC states that it is unable to make comments on Ausgrid's consumer engagement activities because it has had no contact with Ausgrid, specifically as part of our Customer Council. Ausgrid regrets that PIAC has not had this contact. We have invited PIAC to become a member of the Ausgrid Customer Council in the past, but PIAC was unable to accept. We note that the NSW Council of Social Services, the NSW Ethnic Communities Council, the Smith Family and the NSW Council of the Aging are all members of our Customer Council.

We also note that PIAC has participated in face to face and written engagement activities since the publication of our regulatory proposal. We are keen for this relationship and engagement to grow as part of our genuine and ongoing commitment to greater consumer engagement.

UnitingCare Australia

Ausgrid is keen to receive input from important consumer stakeholders on our ongoing operations and regulatory proposals. We note UnitingCare Australia's submission from September 3 2014 and provide the following comments in response.

UnitingCare acknowledged the increasing levels of consumer engagement by NSW Businesses. However, we note that the majority of its criticism of consumer engagement was directed at ActewAGL, not Ausgrid. We also note that a number of examples provided in its submission are sourced from outside the Ausgrid network area.

Ausgrid has sourced all its consumer engagement activity from customers in our network area.

We also note that information about disconnection of electricity customers shows that disconnection rates for non-payment of electricity bills were between 25% and 60% higher in Victoria and South Australia, compared to NSW. We note the details of a Government Information Application from a third party shows that disconnection rates for non-payment across our network area decreased by about 4% in 2013/14.

We also note comments from UnitingCare about consumer engagement generally:

> *We welcome the opportunity to cooperate with energy network businesses to advance their consumer engagement techniques.*

We have invited UnitingCare Australia to participate in a number of key engagement forums, including face to face discussion, surveys and reviews. We are committed to continue this engagement process to further improve our processes.

Ethnic Communities Council of NSW (ECC)

The ECC recommended that Ausgrid and other network businesses engage peak bodies that have good relationships with vulnerable, hard-to-reach communities as part of engagement strategies.

Ausgrid has met with the ECC on two occasions to discuss its draft engagement guidelines for electricity businesses. We have endorsed these guidelines and we are working on effective ways to adopt them into our long-term plans. However, we note that these guidelines were drafted after our regulatory proposals were submitted.

We also note that the ECC states that our proposal is not compliant with the AER Consumer Engagement Guidelines. We do not accept this statement, particularly in light of previous statements made in this chapter regarding the date of publication of the guidelines.

NSW Council of Social Services (NCOSS)

We welcome comments from NCOSS about network business consumer engagement practices, in particular that;

> *In their proposals, all three networks have stated that they will continue to review and refine their consumer engagement strategies. We welcome this commitment.*[93]

And;

[93] NCOSS Submission to the NSW Electricity Distribution Network Price Determinations Ausgust 2014 p.5

We would further add to this that the Networks should make better use of their Customer Councils and their engagement with advocacy peaks to ensure the quality control of broader consumer engagement processes.[94]

Ausgrid looks forward to continued engagement with NCOSS on a range of engagement practices and strategies as outlined in this revised submission.

Total Environment Centre (TEC)

Ausgrid notes the comments from the TEC about engagement with it on our demand management program. We look forward to improving our engagement with the TEC as we further develop and deliver our demand management programs. We worked extensively with TransGrid on its engagement program around network investment programs for the power supply for Sydney's CBD, including presenting on demand management alternatives for the project.

We note that while the AER Draft Determination references stakeholder views as reason for rejecting our proposal, strong calls by the TEC and PIAC to expand support for demand management were dismissed. The TEC and PIAC call for greater levels of investment in demand management alternatives than Ausgrid proposed, yet the draft determination rejected in its entirety the modest level of funding requested for the broad-based demand management program. Furthermore, both the TEC and PIAC endorsed Ausgrid's request for a demand management benefit sharing scheme (DMBSS) to fill an important gap in the Demand Management Incentive Scheme, yet the draft determination rejected this proposal.

Stretch questions and other issues

The Consumer Challenge Panel also set out a number of stretch questions[95] in its submission on our regulatory proposal. We have deliberately framed the contents of this chapter so that we answer these stretch questions. This enables the AER to adequately judge our submission based on a complete set of facts.

The CCP and other groups have also raised concerns about how we have engaged on three matters. We address those issues here:

Public lighting

The AER noted that the main barrier to consumers being able to participate in the consultation process was the confidentiality claims made by Ausgrid over public lighting information. We note that Ausgrid requested that the AER not to publish commercially sensitive information because it would breach the commercial arrangements with suppliers of public lighting components such as lamps and luminaires and compromise our ability to negotiate in the market for the procurement of these items.

As local councils also procure these public lighting components for their own purposes, release of this sensitive information would have also adversely impacted the position of Ausgrid's suppliers in their commercial dealings with councils. To address this issue, Ausgrid is participating in the AER's process to release this information under strict confidentiality provisions to the consultants representing local councils in a manner that preserves the commercial position of all parties, including suppliers.

Further to our Attachment 8.06[96] that was submitted as part of our initial proposal, Ausgrid has a strong commitment to customer engagement as demonstrated by our consultation meetings held in 2014. These are detailed below.

A forum was held with Councils on new approaches to 2015-19 street lighting pricing, this was held on the 26 February 2014 in the Sydney and Hunter region. In addition, we have published working pricing models on our website[97] and all underlying assumptions that do not include any third party commercial in confidence information. By using these models a customer would be able to apply different input prices to calculate the various public lighting charges. This in turn increases engagement and ability to make effective submissions to the AER.

Seminars were also held for Councils regarding contestability and the contestable process as part of the NSW Public Lighting Code that Ausgrid prescribes to. Two seminars were held. The first was held in Newcastle on 8 October 2014 for Councils in the Hunter and the second was held at Silverwater on 15 October 2014 for Councils in Sydney and the Central Coast. The following topics were discussed at these seminars:

- History of contestable electrical works and how it came about.
- The contestable framework.
- Minor capital street lighting works completed by Ausgrid and contestable works to be completed by Accredited Service Providers (ASP).

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[94] NCOSS Submission to the NSW Electricity Distribution Network Price Determinations Ausgust 2014 p.6

[95] The CCP created, what it termed 'stretched questions', to help the AER 'assess the credibility of NSPs claim about consumer engagement activities'

[96] Stakeholder Engagement and Customer Consultations

[97] http://www.ausgrid.com.au/Common/About-us/Newsroom/News-gallery/Network-maintenance/Street-lighting.aspx

- An overview of contestable process with examples and addressing questions and concerns about the timing, cost and the complexity of the process for local councils and Ausgrid's charges related to contestable projects, when they apply and whether the costs are the same for small and large projects.

Two consultation meetings were held with Councils for the upcoming Networks NSW Tender - Street Light Luminaires, Lamps. The first was held in at Silverwater on 6 November 2014 for Councils in Sydney and the second was held at Newcastle on the 7 November 2014 for Councils in the Hunter. The seminar provided details about our current and future strategies regarding LEDs, how we intend to engage the market and details about the tender timetable..

Metering

The AER noted that it published a discussion paper on metering in December 2012 and confirmed its position in our Stage 1 F&A published in March 2013. During that time, the AER noted that it had suggested to Ausgrid that it should consult with its customers on the range of options that might be available. It found there was little evidence that Ausgrid consulted customers on options for how meters could be priced in the future. The AER noted that Networks NSW did conduct a workshop with retailers in May 2014 to provide advance notice of the metering charges in its proposal, but its understanding is that Ausgrid did not otherwise consult on its proposed charges. The AER noted that the absence of this consultation is reflected in submissions from Origin and PIAC which indicated that we developed our metering proposal independent from consumers.

In response we note that this is the first year of a new framework introduced by the AER to encourage greater competition in metering. Given this, we committed to further consultation with retailers on specific issues regarding metering once our substantial proposal had been submitted and our position in response to the new framework had been outlined as the basis for further consultation with stakeholders.

We have noted the feedback from retailers and PIAC on our proposal as part of this consultative process, particularly in relation to exit fees, and acknowledged there needs to be further consultation with them and the AER on exit fees that do not create sovereign risks or introduce cross subsidies between customers.

Rate of Return

The AER noted that there was also broad stakeholder concern that Ausgrid departed from its rate of return guideline with little or no consultation with consumers and without demonstrating that these variations are made in the long-term interests of consumers or represent the efficient costs of an efficient benchmark firm. In response we note that it is not correct.

While the rate of return guideline sets out the methodologies the AER proposes to use in estimating the allowed rate of return for distribution determinations, the guideline is not binding on a DNSP in developing its regulatory proposal or the AER in making a distribution determination.

Throughout the rate of return guideline consultation process, Ausgrid has consistently publicly advocated a return on capital that minimises the impact of short term volatility in financial markets on regulated revenues and consequently consumer prices over time.

As the guideline recommends, we have also clearly outlined in our regulatory proposal the reasons for our approach as:

- Ausgrid has prudently managed refinancing risks over the past 10 years by issuing debt on a staggered portfolio basis and therefore does not face the transitional issues that may be a factor with other network service providers;
- We would be exposed to significant risk arising from differences in market conditions under which our debt was actually raised and the market conditions under which the AER transition allowance assumes debt was raised; and
- Adopting the AER's guideline would effectively encourage Ausgrid to move away from an approach to financing determined as efficient by the AER to an approach it now considers is inefficient (the use of swaps) to manage the interest rate risk introduced by the guideline's short term transition.

The detailed reasons are further elaborated in the CEG report titled "Debt transition consistent with the NER and NEL" which has been available to the AER and other stakeholders since 30 May 2014 when our initial regulatory proposal was submitted.

Conclusion

Ausgrid has clearly undertaken a comprehensive engagement activity that adheres to the AER Consumer Engagement Guideline for Distribution Service Providers, despite those guidelines being published on the eve of our regulatory proposal being submitted. That activity is based on an endorsed strategy built on objectives, principles and processes also consistent with the AER guidelines.

Our engagement activity helped determine consumer views and concerns that were clearly spelt out and addressed in our proposal. We have further demonstrated adherence to the guidelines by our continued effort and focus on genuine and ongoing engagement to ensure our services are in the long term interest of consumers.

We have demonstrated in this revised proposal that the AER has formed an unreasonable view in rejecting our representation of consumer concerns. It has done so based on anecdotal evidence, errors of fact and misrepresentations.

3. Services and price controls

The AER's draft determination did not adopt its own framework and approach that it proposed to apply to Ausgrid. Instead it made some substantial changes to the definitions of the services it regulates and how it will set prices for those services.

Before we were able to submit a regulatory proposal, the AER was required to develop a 'Framework and Approach' paper setting out how it would assess our regulatory proposal and make its determination. The Framework and Approach was required to provide certainty around how our proposal would be considered and help facilitate the development of our proposal. This included decisions on the form (or forms) of the control mechanisms that would apply and the AER's proposed approach to the classification of the services we provide and the incentive mechanisms we would be subject to in the 2014-19 period. The AER set out its proposed approaches with respect to these in its Stage 2 Framework and Approach paper. Our initial proposal in the main adopted these approaches with a few clarifications and/or modifications.

In this chapter, we consider the AER's draft decision on our proposal for service classification and application of incentive schemes and set out our revised proposal in respect of these.[98] We address the AER's draft decision on control mechansims in chapter 9.

3.1 Service classification

Revised proposal

For our revised proposal, Ausgrid has:

- Incorporated the clarification we requested in our initial proposal[99] that the AER has accepted.
- Revised our classification proposal to incorporate the AER's decision on load control services.
- Accepted the AER's decision to recover type 5-6 residual capital costs via the general network tariffs that are charged to standard control services customers and the AER's decision to recover the administration fee from alternative control services customers. While we agree with the AER's decision on the methods of recovering these costs, we however do not consider there is such a service as 'meter transfer' service.

Attachment 3.01 sets out in the services, the service groups and the classification of these groups. This attachment adopts the AER's draft decision detailed in Table 13-1 with some minor changes to the description of some services for clarity. These changes are highlighted in yellow for ease of review.

Response to AER's draft decision

Minor clarifications and re-groupings

The AER incorporated the clarifications proposed by Ausgrid outlined above. In addition, the AER re-organised the grouping of services, with no change to the classification of these services and service groups.

Ausgrid accepts the AER's decision to make these minor clarifications on the basis that they do not represent a material departure from its decision and where relevant, they accorded with the clarifications we sought in the initial proposal.

Changes to classification of load control

In its draft decision, the AER changed the classification relating to load control services. For those load control services provided by devices that are separate to the meters (such as time switches and relays), the AER considered these services to be part of network services and hence classified as standard control services. By contrast, the AER considered that load control services provided by devices that are embedded within the meter are to be classified as alternative control services.

We accept the AER's decision to change the classification of load control services, and we have revised our service classification proposal to incorporate the AER's decision.

The AER's approach is consistent with the methodology we used to prepare our initial regulatory proposal; hence revisions to type 5-6 metering services prices and standard control services revenue are not necessary.

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[98] The relevant attachments of the AER's draft decision that this chapter address, in part or whole, are: Chapter 13 (Classification of services), Chapter 9 (EBSS), Chapter 10 (CESS), Chapter 11 (STPIS) and Chapter 12 (DMIS).

[99] See Ausgrid's initital regulatory proposal, page 17 and Attachment 3.01

Changes to classification of metering services

The AER decided that the recovery of residual type 5-6 metering costs (the recovery of which is triggered by customers switching to an alternative metering provider) to be standard control services. On the other hand, the cost associated with administrating such transfers is to be classified as alternative control services (the 'meter transfer' services').

At the outset, we need to clarify that our classification proposal did not propose 'an additional metering service called metering exit fee' as the AER contended. Our initial proposal accepted the AER's classification of type 5-6 metering services and accordingly, our initial proposal sought to propose a cost reflective price for these services. The exit fee was the means by which we proposed to recover the stranded and avoidable costs associated with the provision of type 5-6 metering services. This fee is triggered when a customer – who up until that point has been receiving metering services from Ausgrid – decides to switch to an alternate metering service provider. This decision to switch gives rise to the stranded cost (residual capital cost) and administration cost.

The AER accepted that Ausgrid is entitled to recover the residual capital costs[100] but considered that this cost should not be recovered as part of an exit fee charged to alternative control services customers. Rather, the AER decided that this cost is to be recovered from general network tariffs via the 'B' factor in the control mechanism.[101] By contrast, the AER decided the cost of administering these meter transfers are to be recovered via an exit fee charged to alternative control services customers.

Ausgrid agrees with the mechanisms for recovering these residual capital costs and administration costs as decided by the AER in the draft decision. However, we do not consider the recovery of these costs constitute a separate service to the Type 5 & 6 metering service as described by the AER as a 'meter transfer' service.[102] For these reasons, we did not propose such a service in our classification proposal included in the initial regulatory proposal. We also note that Appendix A of Attachment 13 of the AER's draft decision does not expressly refer to a separate 'meter transfer' service.

We consider that these activities are better reflected as part of the definition of 'Types 5 and 6 metering provision, maintenance, reading and data services' rather than being defined as a separate service. Our Attachment 3.01 addresses this proposed change.

For avoidance of doubt, we agree that the residual capital cost is to be recovered via the B factor of the control mechanism for standard control service and the recovery of the administrating costs is to be recovered as part of Type 5 & 6 metering alternative control service (via the 'meter transfer fee' – further discussed in Chapter 8).

Our response to the AER's decision on the administration costs is outlined in Chapter 8. Our consideration of the operation of the B factor is detailed in Chapter 9.

3.2 Application of incentive schemes

Revised proposal

Ausgrid's revised proposal on the application of incentive schemes:

Efficiency benefit sharing scheme (EBSS)

We consider that if the AER makes the correct opex decision, it would have no need to suspend the operation of the EBSS. If the AER decides not to accept our revised forecast expenditure and decide to substitute a lower (unachievable) amount then we consider that an EBSS would not provide for a symmetric incentive and therefore should not apply.

Service target performance incentive scheme (STPIS)

We have accepted the inclusion of a STPIS subject to the expenditure forecasts in this revised proposal being accepted. If the AER does not accept our revised forecasts for operating and capital expenditure on which our reliability performance forecasts are based, we propose that no STPIS should apply to the 2015-19 period.

Demand management embedded generation connection incentive scheme (DMEGCIS)

- We accept the draft decision to continue Part A of the Demand Management Innovation Allowance (DMIA) at the proposed level of $1 million per year.
- We do not accept the draft decision to continue to delay consideration of any form of incentive for demand management, and resubmit our proposed Demand Management Benefit Sharing Scheme. We address this issue further below.

Small Scale and Capital Expenditure Incentive Schemes

We have presumed that there is no small scale incentive scheme to apply to Ausgrid for the 2015-19 period.

Consistent with the approach to EBSS, if the AER decides to not accept our capital expenditure proposal and instead substitutes a lower amount, we consider that a CESS would not provide a symmetric incentive and therefore should not apply.

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[100] At times referred to in this revised proposal as 'stranded asset costs'

[101] Chapter 9 and Attachment 9.01 provide our response to the AER's decision on the operation of the B factor.

[102] AER draft decision, Attachment 13, page 13-11

Response to AER's draft decision and reasons

In the section below we set out our revised proposal for incentive schemes.

Efficiency benefit sharing scheme

The AER's draft determination states that no expenditure will be subject to the EBSS in the 2015–19 regulatory control period. The AER made this decision because of its forecasting approach to opex and the likely incentives Ausgrid already faces to improve its efficiency. The AER noted that this also means that no expenditure will be subject to the EBSS in the 2014/15 regulatory control period.

Our contention is that if the AER makes the correct opex decision, it would have no need to suspend the application of the EBSS. The AER's decision is inconsistent with its previously proposed approach. We consider that the AER's reasoning demonstrates that the substitute forecast opex is unachievable, and there would be a high risk of substantial penalties if an EBSS was applied. As we demonstrate in Chapter 6 of this revised proposal, the AER's responsibility is to set an opex allowance that reasonably reflects efficient and prudent costs to enable Ausgrid to achieve the opex objectives. If the AER made such a decision, then an EBSS incentive would provide a symmetrical incentive.

If the AER, however, decides to not accept our proposal and to substitute a lower (unachievable and insufficient) amount which we consider would be contrary to the NER, then we agree that an EBSS would not provide a symmetric incentive, and therefore should not apply.

In addition, the AER now seeks to exclude carry overs of efficiency gains and losses caused by changes in provisions in the draft decision for Ausgrid for the 2015/16 to 2018/19 subsequent regulatory control period by claiming that provisions are an accounting treatment and do not actually represent an expenditure (as required by clause 6.5.8(a) of the NER) from which an efficiency gain or loss can be determined. That is, the AER considers that there is a degree of artificiality to such costs. In our view changes in employee related provisions do represent actual costs incurred by Ausgrid.

There is no rule that explicitly provides discretion for the AER to retrospectively introduce additional excluded cost categories for the EBSS or to revise or review adjustments, and there are strong arguments that the AER is not entitled to do so.

In addition, the February 2008 EBSS that applied to Ausgrid in the previous regulatory control period does not provide for the AER to exclude an additional cost category after the relevant final determination. That is, any decision to exclude an additional category of costs should have been contained in the 2009-14 final determination and not made by the AER after the event.

We consider that such a retrospective exclusion would be contrary to the purpose of incentive based regulation and would not be consistent with 'fair sharing' of efficiency gains and losses under the EBSS. A DNSP cannot be incentivised by retrospective changes to a scheme because the actions that are sought to be incentivised or dis-incentivised have already occurred. Incentives are created by the promise of rewards or penalties. Retrospective changes to either the excluded cost categories or revisions of adjustments made by the DNSPs may instead dis-incentivise DNSPs going forward because there is a risk that the EBSS (or any other regulatory decision) as it is applied to the NSW DNSPs in the future may be different to how the AER represented that the EBSS would apply when it was introduced.

If the EBSS is not applied by the AER in a manner consistent with its previous representation that provisions were not an excluded cost category, then there is a risk that DNSPs will not believe that the AER has the regulatory commitment to keep other regulatory promises. Equally, if revisions of adjustments are made at the end of a regulatory control period, then DNSPs may consider that there is a risk that the AER would review or revise other efficiency gains or losses made. Both these factors jeopardise the incentive features of the EBSS.

Service target performance incentive scheme

Our proposed STPIS parameters and reliability performance forecasts assumed no substantial change to operating practices or investment triggers for both augmentation and replacement. The level of revenue proposed in the draft decision would not have been sufficient to maintain either of these key inputs. If the operating and capital expenditure forecasts in this revised propsal are not accepted we propose that no STPIS apply.

Subject to that caveate, Ausgrid accepts the key components of the methodology proposed in the draft decision for calculating reliability performance targets and the STPIS incentive rates, but has not accepted the proposed reliability performance targets or STPIS incentive rates in the draft decision because of the need to recalculate the rates using updated data for the 2013/14 period.

Ausgrid has accepted the AER's proposed methodology of trend line analysis for the calculation of Ausgrid's reliability targets, on the basis of simplicity and transparency. We have used the AER's methodology to perform an updated trend line analysis using updated data including the actual 2013/14 network performance to develop updated reliability targets for the 2014/15-2018/19 period.

We accept the AER's proposed use of VCR values based upon the AEMO September 2014 Value of Customer Reliability Review Report, including the VCR for CBD.

We have recalculated the STPIS incentive rates using the updated reliability targets, the AER proposed VCR values (modified to incorporate the estimated CPI between September 2014 and July 2015 (the start of the regulatory control period)), and four years of data for energy consumption and smoothed revenue.

Table 2 and Table 3 show the outcomes of our revised calculations and form our revised proposal for STPIS parameters. Details are provided in Attachment 3.02. We note that these numbers are based on Ausgrid's revised proposed revenue and would need to be updated to reflect the AER's final determination.

Table 2 – Updated proposed STPIS incentive rates (%)

Feeder category	Incentive Rate SAIDI	Incentive Rate SAIFI
CBD	0.00683	1.85114
Urban	0.03168	3.02256
Short Rural	0.00427	0.51232
Long Rural	0.00004	0.00587

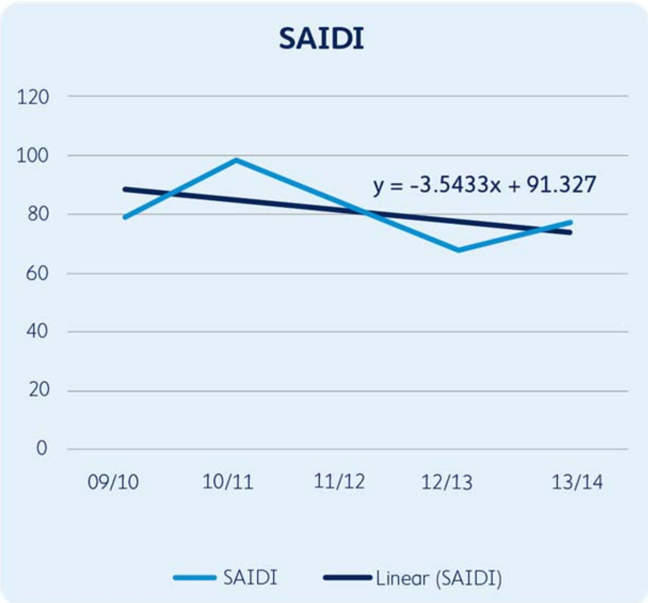
Table 3 – Updated Ausgrid targets based on draft decision methodology

	Performance target based on 5 yr avg.	Proposed target	Difference (%)
Unplanned SAIDI			
CBD	18.17	16.58	8.78
Urban	68.41	62.41	8.78
Short Rural	172.42	157.28	8.78
Long Rural	478.55	436.53	8.78
Unplanned SAIFI			
CBD	0.066	0.054	18.02
Urban	0.823	0.674	18.02
Short Rural	1.739	1.426	18.02
Long Rural	3.766	3.088	18.02

Figure 7 below shows the impact of the updated analysis on the performance target calculations from the draft determination. It mirrors the format of Figure 11-8 from the draft decision[103].

[103] AER draft decision Ausgrid distribution determination 2015-16 to 2018-19, Attachment 11: Service target performance incentive scheme, p. 11-22

Figure 7 – Ausgrid SAIDI & SAIFI trend using 2013/14 actual performance



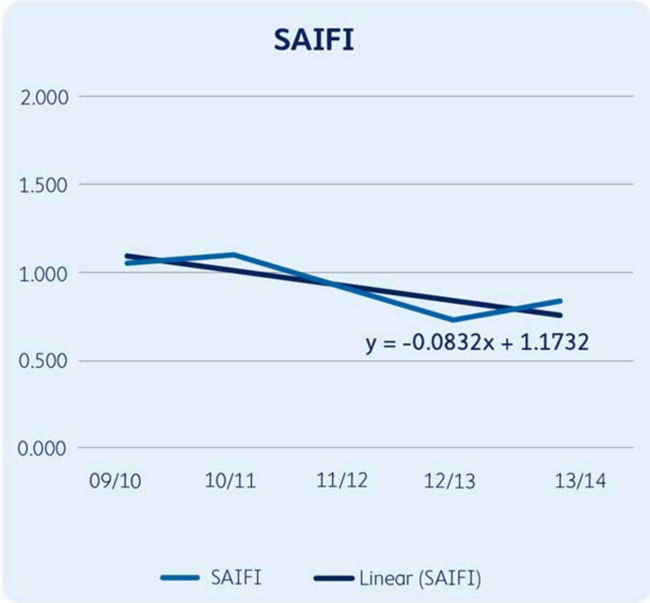


Table 4 – Ausgrid SAIDI & SAIFI

System	2009/10	2010/11	2011/12	2012/13	2013/14	Average	Trend	Difference
SAIDI	78.94	98.21	82.19	67.62	76.52	80.70	73.6108538	8.78%
SAIFI	1.060	1.093	0.907	0.732	0.825	0.924	0.75715033	18.02%

Demand management and embedded generation incentive scheme

The draft decision is to continue part A of the existing Demand Management Innovation Allowance (DMIA) at the previous value of $1 million per year. However, no effective consideration was given to the maintenance of positive incentives for demand management formerly available through the D-Factor.

The draft decision incorrectly asserts that:

> *Ausgrid proposed its DMBSS in anticipation of a series of rule changes which are currently being considered by the AEMC as part of its Power of Choice review.*[104]

> *The move to a revenue cap form of control…provide(s) distributors with opportunities to improve and expand their demand management programs.*[105]

The draft decision identifies these as reasons why it chose not to consider the introduction of any incentive for demand management.

Neither of these is true. There is nothing in the current rules that would prevent the consideration of a DM incentive scheme of the type proposed. Ausgrid's proposal reflects our concern regarding the ongoing absence of any actual incentive for DNSPs to pursue demand management opportunities, and the absence of any mechanism to recognise the value of demand reductions to the wider energy supply chain.

The move to a revenue cap has made no difference to the framework under which demand management operates. The previous arrangements for recovery of foregone revenue neutralised the potentially negative incentive of the price cap. It is appropriate

[104] AER draft decision - Attachment 12: Demand management incentive scheme, p. 12-8

[105] AER draft decision - Attachment 12: Demand management incentive scheme, p. 12-10

that the foregone revenue arrangements should fall away with the introduction of a revenue cap, but that serves only to maintain the status quo, not improve the situation. The loss of the incentive component of the D-Factor now means that this draft decision is less supportive of demand management than the previous AER decision.

On this basis, Ausgrid retains the proposal for a DMBSS in the revised proposal, under the same terms as described in the initial proposal. The details of this proposal were contained in Attachment 3.03[106] to our initial proposal. We also note the details we provided to the AER in response to its questions on our DMBSS proposal.[107] As we have maintained our position in the initial proposal and have submitted this Attachment 3.03 to our initial proposal to the AER, we refer the AER to this Attachment 3.03 instead of re-submitting the same.

Capital expenditure sharing scheme and small scale incentive scheme

The CESS as set out in the AER's November 2013 capital expenditure incentive guideline provides reward/penalty for efficiency gain/loss with respect to capital expenditure. In its distribution determination for the transitional year (i.e. 2014-15), and consistent with the transitional rules, the AER specified that no CESS would apply in 2014-15. The AER proposes to apply its CESS in the 2015-19 regulatory control period in accordance with its published guidelines.

Ausgrid's initial proposal was to apply the CESS in the 2015-19 regulatory period, consistent with the AER's proposed approach as stated in the AER's Stage 2 Framework & Approach (F&A) Paper. The AER's draft determination is consistent with the F&A Paper and our initial proposal, and on this basis we have not revised our proposal.

Consistent with the approach to EBSS, if the AER decides to not accept our capital expenditure proposal and instead substitutes a lower amount, we consider that a CESS would not provide a symmetric incentive and therefore should not apply.

With respect to small scale incentive scheme, the AER's Framework and Approach paper's approach was not to apply the small scale incentive scheme. We supported the AER's decision in our initial proposal.

The AER has not made an explicit decision not to apply the scheme in its draft determination. We consider that there is no change to the AER's proposed approach not to apply the scheme in the 2015-19 period and have presumed the AER's draft decision is not to apply a small scale incentive scheme to Ausgrid.

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[106] DMEGIS Proposal 2014-19 (see Attachment 3.03 of Ausgrid's initial proposal)

[107] Ausgrid's response to the AER's information of 11 July 2014 (AER Ref: AER Ausgrid 012)

4. Building block proposal

The AER did not accept many of the elements of our building block proposal. In this chapter we set out our response to the AER's decision and reasons for the decision with detailed analysis on rate of return, capex and opex presented in subsequent chapters and relevant attachments.

We have made a number of revisions to our building block proposal to incorporate changes to underlying inputs, which have a consequential impact on proposed revenues and prices.

In our initial proposal, we identified the building block components we have used to calculate the annual revenue requirement for each year of the regulatory control period,[108] consistent with the rules requirements. The building blocks relate to the following types of costs:

- ***Return on capital***. We receive an allowance for a return on capital. This is to finance our debt and provide a reasonable return on equity for the funds we borrow or raise through debt and equity to fund investments. The calculation of the return on capital is based on key inputs including the value of the opening asset base, the allowed rate of return and forecast capital expenditure.
- ***Return of capital***. We receive an allowance for a return of capital (depreciation). The calculation of the return of capital is based on key inputs such as the value of the opening asset base and the remaining lives of assets and is calculated on a straight-line basis. The AER offsets changes in indexation of the RAB through its depreciation calculation and refers to this as 'regulatory depreciation'.
- ***Forecast operating expenditure and corporate income tax costs***. We receive a revenue allowance to fund our operating activities and to meet our income tax liabilities.
- ***Other revenue increments or decrements***. We receive a revenue increase or decrease based on outstanding penalties or rewards from incentive schemes that applied in the 2009-14 period. The rules also enable a revenue decrement arising from the use of assets that provide standard control services to provide certain other services.

As part of the building block proposal, we had also proposed nominated pass through events for the 2015-19 regulatory period.

In the sections below we set out our response to the AER's decisions on these matters, with detailed response on allowed rate of return, forecast capex and forecast opex in Chapters 5, 6 and 7 respectively.

4.1 Revisions to proposal

The AER did not accept/approve all elements of our building block proposal except for:

- Revenue increment/decrement from the application of DMIS during the 2009-14 period.
- Shared asset reduction.
- Method for indexing the RAB.
- Commencement and length of the regulatory control period.

The AER's decisions on our proposed annual revenue requirements are consequential to the decisions made by the AER in its draft determination on other aspects of our building block proposal.

For our revised proposal, we have not incorporated the AER's decision on:

[108] We note that while this proposal relates to the subsequent regulatory control period, the Rules require us to treat the 2014-15 transitional year as if it were the first year of the period. See clause 11.56.4.

- The return on capital component of the building block revenue. The return on component is dependent upon the AER's draft decision on:
  - The value of the opening RAB – we have incorporated the AER's decision on this element in our revised proposal.
  - Forecast capex – we have not revised our proposal to incorporate the AER's decision on our proposed forecast capex. We address the AER's reasons, analysis and reasons on forecast capex in chapter 5.
  - Allowed rate of return – we have not revised our proposal to incorporate the AER's draft decision on the allowed rate of return and the estimation methodology for cost of debt. We address the AER's decisions on these elements in chapter 7.
  - The return of capital component (regulatory depreciation) principally because we have not incorporated the AER's decision on forecast capex. Further, for our revised proposal on regulatory depreciation, we have:
    - Incorporated the AER's draft decision on the method for indexing the regulatory asset base and straight line deprecation method. We note that the AER will update its forecast of inflation for the latest RBA estimates at the time of the final determination. For the revised proposal, we have used the AER's draft decision of 2.5% as a placeholder.
    - Reflected the revised forecast capex for the 2014-19 period.
- Forecast operating expenditure. We instead have incorporated our revised forecast opex in the calculation of the revised annual revenue requirement. We address the AER's decisions, analysis and reasons on forecast opex in chapter 6.
- Estimated costs of income tax principally because we have not incorporated the AER's decision on the value of imputation credit or the AER's decision on forecast capex and allowed rate of return. We however have incorporated the AER's decision on the opening value of the tax asset base for transmission and proposed a minor amendment to the value of distribution asset base.
- Proposed carry over amounts from the application of the EBSS during the 2009-14 period.

Whilst we have not revised our proposal to reflect the AER's decision on the EBSS carryover amount, we have however incorporated the AER's decision on the carry over amount from the application of DMIS and revised these amounts to reflect the latest audited actuals for 2013/14.

Because we have not incorporated the key elements of the AER's decisions on the building block approach, we have not revised our proposal to incorporate the AER's draft decision on annual revenue requirements, proposed smooth revenues and X-factors. Instead we have made revisions to most elements of our building block proposal. The revisions are outlined in this chapter and / or in subsequent chapters for allowed rate of return, forecast capex and forecast opex.

The AER also made draft decisions on Ausgrid's proposed depreciation approach to establishing the RAB as at 1 July 2019 and Ausgrid's nominated pass through events. In respect of these decisions, Ausgrid:

- Concurs with the AER's decision that the forecast depreciation approach is to be used in establishing the RAB as at 1 July 2019. No further consideration is necessary.
- Accepts the AER's decision on connection policy. However we have proposed some minor amendments to the policy as outlined below.
- Does not agree with the AER's draft decision on nominated pass through events and hence has not incorporated this decision in the revised proposal. In response to the AER's decision and reasons for the decision on nominated pass through events, we have revised the definition of the pass through events we nominated in the initial regulatory proposal to ensure clarity.

4.2 Our response to the AER's decision

Return on and of capital

The AER did not accept our return on and of capital based on its decision not to accept the opening value of the RAB, proposed forecast capex and proposed allowed rate of return.

We do not accept the AER's reasons for rejecting our proposed allowed rate of return and forecast capex and consequentially have not revised our proposed return on and of capital to reflect these decidions. We have provided a detailed response to the AER's decisions on forecast capex and allowed rate of return in Chapter 5 and 6 of this document. In the sections below, we set out our comments on the AER's decision on the value of the opening asset base and depreciation schedules. The revised return on and of capital of the annual revenue requirement for the 2014-19 period is shown in Table 11.

Opening value of regulatory asset base

The AER made a number of adjustments to our proposed value of the RAB as at 1 July 2014 (opening RAB values). We agree with these adjustments and have incorporated the following opening RAB values in the calculation of our revised return on capital component of the annual revenue requirement.

Table 5 – RABs as of 1 July 2014

$m; nominal	Value as at 1 July 2014
Distribution SCS	12,251.7
Transmission SCS	2,035.7
Type 5-6 metering services	267.2

Our revised roll forward models for distribution and transmission RAB are at Attachments 4.01 and 4.02. We have also provided at Attachment 4.03 the revised calculation for Type 5/6 metering services RAB.

Forecast capex

The AER did not accept Ausgrid's proposed forecast capex for the 2014-19 period and instead substituted for an amount of $2,546.4 million ($2013/14). We have not revised our proposal to incorporate all aspects of the AER's decision. Our detailed response to the AER's draft decision on forecast capex is in chapter 5.

Table 6 shows Ausgrid's revised forecast capex for the 2014-19 period.

Table 6 – Revised forecast capex ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Forecast capex	766.2	864.3	819.0	699.9	606.1	3,755.5

Allowed rate of return

The AER did not accept our proposed allowed rate of return and the parameters for calculating this rate. Ausgrid's detailed consideration and response on the AER's decision on allowed rate of return, the return on debt can be found in Chapter 5 and associated attachments. Ausgrid's revised proposal for the allowed rate of return is shown in Table 7.

Table 7 – Allowed rate of return (%)

Rate of return parameters	Revised proposed values
Overall rate of return	8.85
Cost of equity	10.15
Cost of debt	7.98
Gearing	60
Utilisation of imputation credit	25

Regulatory depreciation

The AER did not accept Ausgrid's proposed regulatory allowance mainly because of the consequential impact of its decision on Ausgrid's proposed forecast capex for the 2014-19 period and opening RAB. Nevertheless, the AER accepted other aspects of Ausgrid's calculation of regulatory depreciation namely proposed asset classes, the use of straight line depreciation method and standard lives. No revision for these aspects of the calculation of regulatory depreciation is therefore needed.

The calculation of regulatory depreciation is also dependent upon the remaining lives used to depreciate the opening RAB asset classes. Our initial proposal provisionally adopted the AER's preferred approach of calculating the remaining lives pending further investigation. Our initial proposal noted that the AER's preferred method over-estimates the remaining lives as new assets are given more weighting. We noted that our preliminary analysis showed that the AER's preferred approach to calculating remaining asset lives significantly over-weights new assets and therefore over-estimates the remaining life of assets on our network. This is currently resulting in under-compensation for depreciation expense. One indicator of remaining asset lives is that used for accounting purposes. For depreciable assets as at 1 July 2014 Ausgrid has a weighted average remaining life of 36.6 years according to the AER's approach, but an actual weighted average remaining life for accounting purposes of 25.7 years.

This higher estimated remaining life for regulatory purposes under-estimates actual depreciation expenses that are likely to be incurred by Ausgrid over the 2014-19 period. As noted in Chapter 1, we consider that this further exacerbates the financial sustainability of the AER's decision.

We have engaged Advisian to review both standard and remaining asset lives. Advisian's report is at Attachment 4.04 and shows that the standard lives currently used in the calculation of the annual revenue requirement are not reflective of the economic life of the assets.

The Advisian report highlights that Ausgrid claims regulatory depreciation over a substantially longer period and will also recover their existing RABs over a much longer period than other DNSPs. There is therefore a case to reduce the standard lives used, which increases the value of revenue recovered due to a higher depreciation charge, which is only partially offset by a lower return on capital.

Shortening the standard and remaining asset lives assumptions would enable the businesses to:

- Address the inconsistency between the technical lives reported in the annual RINs and the standard lives used for regulatory depreciation;
- Align the standard lives with the lives used by other DNSPs; and
- Protect against network bypass. Technology changes and reducing costs of off-grid supply options have the potential to create genuine competition for network business. This competition may have the effect of constraining the maximum prices that may be charged by network businesses, and therefore the capacity for cost recovery. Increasing the rate of depreciation in the period while the direct competition for network services is low and the price elasticity of demand similarly is low, as opposed to increasing prices if (or once) direct competition for network services emerges, may help guard against the risk of not being able to recover costs in future.

In order to recover past efficient investment over a reasonable timeframe that minimises the risk of network bypass as noted above, while at the same time constraining average distribution network charges to the rate of change of inflation requires a shortening of the standard and remaining lives assumptions over time. Therefore, Ausgrid has not shortened its standard and remaining lives in this revised proposal, but notes its intention to move in this direction in subsequent regulatory determinations.

Clause 6.5.5(b)(1) of the rules requires depreciation schedules to conform to a number of requirements, one of which is that 'the schedule 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'.

While we have not revised our standard or remaining lives in this revised proposal, we have provided our initial analysis on this matter in anticipation of updating these lives at the subsequent (i.e. 2019-24) determination. Attachment 4.04 outlines the rationale and quantum associated with a change to future standard and remaining lives to address, amongst other things, the impact of technological change and the ability to recover efficient costs in future.

Operating and tax costs

The AER did not approve our proposed forecast opex for the 2014-19 period. We do not accept the AER's decision, reasons or analysis. Our detailed response to the AER's decision is set out in Chapter 6 of this document. We have revised our proposed forecast opex for the 2014-19 period to incorporate the latest inputs and our performance to date. Table 8 shows the revised forecast opex.

Table 8 – Revised opex forecast ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Forecast opex	528.4	553.2	536.1	531.7	529.9	2,679.3

The AER also did not accept our proposed cost of corporate income tax. This was mainly due to the AER's decision:

- Not to accept Ausgrid's proposed opening value of the tax asset base (TAB).
- Not to accept Ausgrid's proposed value of imputation credit.

With respect to the AER's draft decision on the value of the TAB, we accept the AER's decision on

- The opening value as at 1 July 2014 for transmission of $1,502.1 million.
- The standard and remaining asset lives. We note that the AER decided to change the tax asset life for the 'equity raising costs' asset class to five years. We concur with this change.

We have incorporated the above values in the calculation of the revised estimates of corporate tax for the 2014-19 period.

Ausgrid and the AER consulted on the calculation of the tax asset base prior to the publication of the draft decision. At the time, we concurred with the AER's proposed approach of allocating the tax asset values to type 5-6 metering services to reflect the change in classification.

Upon further review, we identified an inconsistency between the approach undertaken to allocate the metering RAB and the approach undertaken to allocating the tax asset values. To ensure consistency between the two, we propose to adopt the same approach to allocate metering RAB for the allocation of the tax asset values for metering. This amendment resulted in a very minor change to the AER's draft decision opening tax value for distribution and types 5-6 metering assets. The revised tax values for distribution is $8,559.3 million (compared to $8,562.4 million in draft decision) and for type 5-6 metering is $245.9 million (compared to $242.8 million in the draft decision).

On the imputation credit input into the calculation of corporate tax, our initial proposal proposed a value of 0.25. The AER rejected this value and substituted for a value of 0.4.

We do not accept the AER's decision on the value of imputation credit and consequently have not revised our estimate of corporate tax to incorporate the AER's decision. Chapter 7 of our proposal sets out our detailed reasons why we consider the AER should have accepted our proposed value of imputation credits. The revised gamma for this proposal is 0.25.

The AER's substituted estimate of corporate income tax was also the consequence of the AER's decision on other areas of the building block proposal such as forecast capex and allowed rate of return. Our responses to these other decisions are detailed in other parts of this revised proposal. Ausgrid's revised estimate of corporate income tax is reflective of our revisions to other elements of the building block approach and is shown in Table 9.

Table 9 – Corporate Income Tax ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Revised corporate income tax	150.7	165.4	171.8	193.7	145.3	826.9

Other proposed revenue adjustments

The rules require that the AER allow Ausgrid to include revenue increments or decrements that relate to the operation of incentives from the 2009-14 period. The rules also require a revenue decrement for shared assets arising from the use of assets that provide standard control services to provide certain other services, subject to a materiality threshold.

The AER has accepted our proposal that there should not be a revenue decrement for shared assets. The AER has also accepted our proposed method to include the lagged carry over amount for the operation of the DMIS as part of changes to annual prices. Our revised proposal incorporated these elements of the AER's decision with revision to the amount of revenue increment / decrement to reflect that actual results for 2012/13 and 2013/14. These updated amounts are shown in Table 10 below. The revised calculation is provided in Attachment 4.05.

Ausgrid has also re-assessed the materiality of the use of shared asset other than for standard control services based on our revised smoothed revenue (prior to shared asset reduction). Table 10 shows this assessment and demonstrates that no shared asset revenue reduction is necessary as the use does not meet the materiality threshold established in the AER's shared asset guidelines.

Table 10 – Annual revenue ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Forecast unregulated revenue from shared asset	13.0	13.2	13.5	13.8	14.0	67.4[109]
Smoothed revenue (prior to shared asset reduction)	2,209	2,338	2,404	2,471	2,540	11,963
Materiality percentage (%)	0.59	0.57	0.56	0.56	0.55	0.56

Note: Numbers may not add due to rounding.

EBSS carry over amount from operation of scheme in 2009-14

The AER however has not accepted Ausgrid's calculation of the revenue increment from the application of the EBSS in the 2009-14 period. The AER did not accept Ausgrid's calculation because:

> *It is not satisfied Ausgrid's proposed EBSS carryover amounts comply with the requirements in the EBSS Ausgrid operated under during the 2009-14 regulatory control period. The difference between our calculations of the EBSS carryover amounts and Ausgrid's proposal is due to the treatment of expenditure recorded as provision.*

On this basis, the AER substituted Ausgrid's calculated carryover amount with its own calculated amount of $260.3 million.

We do not accept the AER's draft decision for the reasons below. Consequently, we have not incorporated the AER's substituted amount in our revised annual revenue requirement. Ausgrid considers that the AER's carryover amount is incorrect because:

- It was not calculated in accordance with the EBSS scheme that the AER determined should apply to Ausgrid for the 2009-14 period.
- The AER's contention that provisions are not costs and hence should be excluded from the calculation is not right.
- Assuming the AER's contention that provisions are not costs and therefore should be excluded (a point that we do not agree with), the AER has made an error in its calculation by excluding this amount from the actual opex only and not the forecast opex.

[109] See Reset RIN, regulatory template 7.4 submitted with Ausgrid's initial proposal.

Compliance with the AER's EBSS scheme

The AER decided to apply the EBSS released in February 2008 (2008 EBSS) to Ausgrid for the 2009-14 period with the resulting financial results from the application of this scheme having effect in the subsequent period (i.e. 2014-19). The applicable EBSS allowed for the exclusion of certain opex categories from the application of the scheme.

In deciding how the 2008 EBSS should apply to Ausgrid, the AER decided to exclude debt raising cost, self-insurance costs, insurance costs, superannuation costs relating to defined benefits and retirement schemes and non-network alternative costs from the operation of the EBSS. That is, these costs were excluded from the total forecast the AER determined for Ausgrid when applying the 2008 EBSS.

Specifically the AER determined a total opex allowance for Ausgrid of $2,628.1 million ($2008/09) from which the AER excluded $101 million ($2008/09) to arrive at a total forecast opex of $2,527.1 million ($2008/09) as the total forecast opex for the purpose of applying the EBSS and particularly for the purpose of calculating the efficiency gains/losses to be carried over to the 2014-19 period. In its decision, the AER unequivocally stated that:

> *In accordance with clause 6.3.2(a)(3) of the transitional Chapter 6 rules the EBSS to apply to the NSW DNSPs is as specified in this section 13.6.*

Nowhere in its final determination or its 2008 EBSS has the AER specified that 'movement in provisions' is to be excluded from the calculation of the carryover amount.

Throughout the 2009-14 Ausgrid submitted the actual opex to be used in applying the 2008 EBSS to the AER in the annual regulatory accounts (or RIN). The format of this RIN is specified by the AER and in relation to the information on EBSS opex, the AER required Ausgrid to report the actual opex incurred for each of the cost categories the AER excluded from the operation of the EBSS in its final determination for Ausgrid.

Ausgrid complied with this request and clearly identified the actual opex of each year of the 2009-14 period that are to be subject to the operation of the EBSS.

We used these actual opex amounts in our calculation of the carryover amount we proposed in our initial proposal. We consider that we have applied the scheme correctly and have complied with the AER's final determination as to how the scheme is to be applied and the carryover amount is to be calculated.

Further, the 2008 EBSS states:

> *In calculating the benefits or losses to be carried over, the measurement of actual expenditure over the regulatory control period must be done using the same cost categories and methodology used to calculate the forecast expenditure for that period. Adjustments will be made where necessary to correct for variances in cost categories and methodologies, and errors.*

There are no adjustments necessary to correct for variances in cost categories and methodologies and errors. The AER's draft decision to exclude movements in provisions contravenes its 2009-14 determination and applicable guideline. The decision is tantamount to a retrospective change and application of the scheme.

Movement in provisions

The AER contended that:

> *movements in provisions should be excluded from the EBSS calculations. This is because the increases in provisions do not represent the actual cost incurred in delivering network services when calculating efficiency gains or losses.*

We consider that amounts set aside in provisions are costs incurred in the provision of standard control services. The fact that it is set aside and to be paid in the future does not change its nature of being a cost incurred in the providing the services.

In order to provide standard control services, Ausgrid must employ resources (i.e. staff) and have systems and processes in place to provide this service (e.g. IT systems etc). At times and where appropriate and efficient to do so, we also employ contracted services. A person, employed by Ausgrid is entitled to receive a salary and other entitlements which are annual leave, sick leave, superannuation and long service leave. To Ausgrid, the total cost of employing this person is the total cost of that person's salary and the costs of his/her entitlements. From a different perspective, this is the costs that Ausgrid must bear in order to provide standard control services to customers, for example, maintain the network etc.

The timing of cash outlay to satisfy these salaries and entitlements that Ausgrid's employees are entitled to does not of itself change the nature of the cost or the purpose for which it is being incurred. The employment of a technician (for example) is necessary in order to provide network services; and the cost of employing that technician comprises of salary payments and leave entitlement. Ausgrid has 'consumed' the service provided that person at the time the person provided the service (e.g. fix damage on the network) and the total cost to Ausgrid of 'consuming' that service is the salary and leave and other entitlements. The fact that the salary component of the cost is paid almost simultaneously with the consumption of the service and the leave entitlement is paid when that person takes leave does not magically alter the nature of the costs. Instead of paying cash immediately, provisions are simply the setting aside of the portion of the total costs that Ausgrid has incurred in providing network services and that provisions are called upon when the person takes leave, which could be many months after the time that the services for which the costs were incurred was performed. It is a fallacy to assert that movements in provisions are not actual cost incurred in delivering network services.

Consider the alternative of Ausgrid employing a contractor to perform the same tasks that an employee would need to do, Ausgrid's cash payment to the contractor would be inclusive of the salary equivalent and the leave entitlement equivalent that Ausgrid would need to pay to the employee.

By endorsing this approach, the AER can be said to be acknowledging that the costs that the AER incurs in performing its functions comprise only of the cash salary it pays to its employees and nothing else. The costs relating to its employees entitlements are not actual costs required by it to perform its functions and provide its services and therefore no funding should be given for these costs (which would, similar to Ausgrid's, be reflected in provisions in the AER's financial accounts).

Ausgrid has engaged Ernst & Young (EY) to consider the AER's approach towards movements in provisions in the draft determination. The EY report is provided as Attachment 4.06.

Consistency with forecast opex

The AER also asserted that its decision to exclude movements in provisions is consistent with the 2008 EBSS because the 2008 EBSS stated that:

> *In calculating carryover gains or losses, the AER must be satisfied that the actual and forecast opex accurately reflects the costs faced by the DNSP in the regulatory control period.*

The AER contended that the movements in provisions are not actual costs incurred in delivering network services. The AER however have ignored the forecast opex in its calculation. As stated above, the AER's final determination for Ausgrid for the 2009-14 period decides that a number of cost categories (of the total forecast opex) are to be excluded from the operation of the EBSS. Accordingly, the AER excluded these cost categories from the total forecast opex in arriving at a forecast opex for the purpose of applying the EBSS. Movements in provisions were not one of the exclusions.

Now the AER retrospectively changed the operation of the scheme by excluding movements in provision from actual costs as it contended that movements in provisions are not actual costs. To be consistent with its own guidelines, the AER must also adjust the forecast opex for this change in approach. We are not advocating for such change but rather that the EBSS carryover be calculated correctly; that is, not excluding movements in provisions.

Retrospective adjustments to incentive mechanisms

Notwithstanding our concerns with the AER's ability to set aside the 2009-14 determination and to redefine the exclusions to the carryforward, perhaps a more significant issue is the impact on incentives arising from the AER's restrospective adjustment to the EBSS as it applies to Ausgrid.

We are not aware of any rule that explicitly provides discretion for the AER to retrospectively introduce additional excluded cost categories for the EBSS or to revise/review adjustments, and there are strong arguments that the AER is not entitled to do so.

The NER provides an incentive based regulatory regime for DNSPs. This is reflected in the mandatory requirement for the AER to develop an "incentive scheme or schemes… that provide for a fair sharing between Distribution Network Service Providers and Distribution Network Users…" of efficiency gains and losses under clause 6.5.8(a) of the NER. The focus on incentives is further emphasised by the factors that the AER must have regard to when developing and implementing the EBSS in clause 6.5.8(c) of the NER, which include:

> *(1) 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 Distribution Network Service Providers;*
>
> *(2) the need to provide Distribution Network Service Providers with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure;*
>
> *(3) the desirability of both rewarding Distribution Network Service Providers for efficiency gains and penalising Distribution Network Service Providers for efficiency losses;*
>
> *(4) any incentives that Distribution Network Service Providers may have to capitalise expenditure; and*
>
> *(5) the possible effects of the scheme on incentives for the implementation of non-network alternatives.*

A DNSP cannot be incentivised by retrospective changes to a scheme because the actions that are sought to be incentivised or dis-incentivised have already occurred. Incentives are created by the promise of rewards or penalties. Retrospective changes to either the excluded cost categories or revisions of adjustments made by the DNSPs may instead dis-incentivise DNSPs going forward because there is a risk that the EBSS (or any other regulatory decision) as it is applied to the NSW DNSPs in the future may be different to how the AER represented that the EBSS would apply when it was introduced.

If the EBSS is not applied by the AER in a manner consistent with its previous representation that provisions were not an excluded cost category, then there is a risk that DNSPs will not believe that the AER has the regulatory commitment to keep other regulatory promises. Equally, if revisions or adjustments are made at the end of a regulatory control period, then DNSPs may consider that there is a risk that the AER would review/revise other efficiency gains or losses made. Both of these factors jeopardise the incentive features of the EBSS.

For the above reasons, Ausgrid has not revised its proposal to incorporate the AER's decision or reasons for that decision. Table 11 shows the EBSS revenue from the application of the AER's approved scheme. The calculation is provided at Attachment 4.07.

Annual revenue requirement

For the reasons above and in Chapters 4, 5 and 6, Ausgrid's has revised its proposed annual revenue requirements based on revised inputs into the building block calculation. This section sets out the revised annual revenue requirement, smoothed revenue and X factors. We also address the AER's draft decision on the true up for the transitional year.

The annual revenue requirement, smoothed revenue and X factors were calculated using the Post Tax Revenue Model that incorporated two main amendments, being calculations on debt raising costs and corporate income tax. These amendments, amongst others, reflect Ausgrid's comments submitted to the AER as part of the current consultation to on the PTRM.[110]

Ausgrid's PTRM for the revised proposal can be found at Attachments 4.08 and 4.09.

Unsmoothed annual revenue requirement

Table 11 shows the revised annual revenue requirement for each year of the 2014-19 period.

Table 11 – Annual revenue requirement ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Return on and return of capital						
Return on capital	1,264.1	1,317.2	1,378.5	1,439.1	1,494.6	6,893.5
Regulatory depreciation	144.7	168.4	195.0	163.5	165.3	837.0
Operating and tax costs						
Opex	548.9	588.4	585.4	596.3	609.7	2,928.8
Income tax	150.7	165.4	171.8	193.7	145.3	826.9
Other revenue increments or decrements						
EBSS revenue	102.2	114.4	89.8	148.2	-	454.7
Proposed DMIA revenue	1.3	1.9	1.4	0.6	0.1	5.3
D-factor carryover	1.6	1.2	-	-	-	2.8
DMIA carryover	-	2.3	-	-	-	- 2.3
Shared asset revenue	-	-	-	-	-	-
Annual revenue requirement	**2,213.7**	**2,354.5**	**2,421.9**	**2,541.4**	**2,415.1**	**11,946.6**

Note: Numbers may not add due to rounding.

Smoothed revenue and X-factors

Ausgrid's proposed smoothed revenues and the resultant X-factors should minimise the price variations over the course of the regulatory period.

In determining them we have considered:

- Our customers, who want prices to be stable over the period.
- The complexities that arise from the inclusion of the transitional year.
- Forecast changes in energy consumption over time.
- The desirability of minimising differences between the annual revenue requirement and smoothed revenue of the last year, i.e. 2018/19.

This smoothed revenue and X- factor profile has been calculated using the AER's PTRM and ensures that our proposal smooth revenues are equal to required revenues in net present value terms. This profile is shown Table 12 and Table 13.

[110] Networks NSW submission on proposed amendment to post-tax revenue model-17 November 2014. Available at www.aer.gov.au

Table 12 – Smoothed revenue ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19
Distribution	1,956.4	2,075.5	2,129.9	2,185.7	2,243.0
Transmission	252.3	262.9	274.0	285.5	297.5
Total	**2,208.8**	**2,338.5**	**2,403.9**	**2,471.2**	**2,540.5**

Note: Numbers may not add due to rounding.

Table 13 – Ausgrid's proposed X-factor outcomes – standard control services (%)

	2015/16	2016/17	2017/18	2018/19
Distribution	-3.50	-0.12	-0.12	-0.12
Transmission	-1.66	-1.66	-1.66	-1.66

Ausgrid looks forward to engaging with the AER on this important issue to ensure that the AER's decision on the X-factor promotes the long-term interests of electricity users by aligning tariff revenues with underlying costs in a manner that does not inadvertently undermine the opportunity for Ausgrid to improve the efficiency and equity of its current tariff structures.

Indicative prices

Ausgrid's revised proposal provides for real reductions in forecast average distribution network charges for customers of 0.6% by the end of the period, which result in a level that is sustainable and avoid further price shocks. This reflects changes in our smoothed revenue as well as changes in our energy forecasts. Our revised energy forecast is provided at Attachment 4.10 and is based on latest data, and represents a 1.8% increase compared to our initial proposal. This is set out in Table 14.

Table 14 – Forecast energy consumption (GWh per annum)

	2014/15	2015/16	2016/17	2017/18	2018/19
Initial proposal	25,056.6	24,943.5	24,795.4	24,911.9	25,084.9
Revised proposal	25,482.3	25,430.6	25,361.4	25,377.1	25,397.3

Note: Numbers may not add due to rounding.

True up for the transitional year.

The rules require a true up for any differences between placeholder revenues approved for 2014-15 in the AER's transitional determination and the revenue allowances applied in the final 2014-19 determination. The rules also allow the AER to apply a true up for alternative control service charges applied in 2014-15 and the charges approved in the AER's final determination.

However, due to the complexity in the operations of other provisions of the transitional rules, giving strict effect to the true-up was rather complicated. We understand the AER's draft decision intends to effect the true-up for both standard control services and alternative control services in standard control services revenue, i.e. via DUOS charges. We concur with this approach as it is the most practical solution and we seek to engage with the AER further on how exactly to calculate and apply the true-up.

In the interim, to facilitate the true-up process, we outline our views on the best approach below.

Ausgrid proposes that a 'true-up' mechanism should be calculated for the services covered by a price cap differently to those covered by a revenue cap.

Revenue cap form of control

The amount of 'true-up' for standard control services is governed by the rules and is relatively straightforward. The smoothing mechanism used in the AER's PTRM lends itself to providing a true up for the 'cost estimates' that were used to calculate the transitional year revenue. That is, if the AER's final determination sets a 2014/15 building block revenue requirement different to that of its transitional determination, then it can use the x-factors to ensure that the PV of revenues across the 2014-19 period are equivalent to the unsmoothed building block revenues approved in the AER's final determination. This ensures an appropriate true-up occurs for SCS in the AER's final determination.

Price cap form of control

Under a price cap, such as applied to all of the alternative control services a true-up is a little more complicated. This is because the relevant control is supposed to be on prices, not revenue. It was further complicated because some of the transitional prices were based on a simple CPI increase in prices and not based on an assumed cost building block.

For the services covered by a CPI increase, the true-up should be based on the difference between:

- The revenue recovered through the transitional prices in 2014/15; and
- The revenue that would have been recovered if the AER had made its full determination for the FY15 year.

For those services that had transitional prices calculated based on cost building blocks for FY15 the true up should be calculated as the difference between:

- The building block costs applied to calculate the transitional prices; and
- The building block costs applied in the final determination for the calculation of prices for FY15.

The under/over recovered revenue and costs would then establish a 'true-up' amount to be recovered/rebated in prices or revenues during 2015/16 to 2018/19. The simplest method of recovering this amount, which we expect to be relatively modest, is to include this amount in the FY15 annual revenue requirement for DUOS.

Pass-through events

The pass-through mechanism in the NER recognises that a DNSP can be exposed to risks beyond its control, which may have a material impact on its costs. A cost pass-through allows a business to seek the AER's approval to recover (or pass through) the costs of a defined, unpredictable, high-cost event. In our initial proposal we nominated 4 pass through events including Insurance cap event; Natural disaster event; Terrorism event and Insurer's credit risk event.

This section responds to the AER's draft decision on nominated pass through events as detailed in the AER's draft decision, Attachment 15: Pass through events.

The AER's draft determination accepted insurance cap event, natural disaster event, terrorism event as nominated pass through event for the 2015-19 with modifications to Ausgrid's proposed definitions of these events. The AER however did not accept insurer's credit risk event as a nominated pass through events.

Revised proposal

Ausgrid's revised proposal:

- Accepts the AER's decision that insurance cap event, natural disaster event and terrorism events are nominated pass through events.
- Does not agree with the AER's assessment of insurer's credit risk event is not a pass through event; consequentially we have maintained our nomination that this event should be a pass through event.
- Revised our proposed definitions of these events in light of the AER's draft decision to provide clarity and distinction between the defining of these events and the assessment criteria which should not be part of the definition of a pass through event.

Ausgrid submitted Attachments 4.12 and 4.13 in support of its proposal on nominated pass through events. These attachments remain our regulatory proposal on pass through events save for the definitions of pass through events in sections 5.2, 6.2 and 7.2 of Attachment 4.13. The definitions in these sections are now replaced by those outlined below.

Response to AER's draft decision

Insurer's credit risk event

The AER did not accept insurer's credit risk event because it considered a prudent service provider could reasonably prevent an event of that nature from occurring. This is on the basis of part c of the nominated pass through event considerations which is:

> *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.*

The AER consider that a prudent service provider would use an insurance provider that has the capacity to satisfy any claims under a policy. The AER claims that NSPs can assess the viability of an insurer by reviewing its track record, size, credit rating and reputation. The AER claims that the inclusion of this event removes the incentive for Ausgrid to obtain insurance from a reputable provider who is able to pay a claim. The AER considers that Ausgrid is able to take steps to mitigate or prevent this event from occurring.

We do not concur with the AER's decision and reasons which we consider are incorrect. It is not apparent that the AER, in reaching its decision to not approve the Insurer's Credit Risk Event, has considered all the material put before it by Ausgrid. For example, the AER in making a statement that 'NSPs can assess the viability of an insurer by reviewing its track record, size, credit rating and reputation' it fails to demonstrate that it has considered our risk management methodology or that it reviewed the external Ernst & Young's regulatory treatment of risk report (Attachment 4.12 of Ausgrid's initial proposal). This material established a clear basis for the AER conclude Ausgrid's insurance arrangements encompass a robust and thorough renewal and review process; and the nominated pass through events (including the Insurer's Credit Risk Event) proposed by Ausgrid are appropriate because they capture the risks which are beyond the control of the NSW DNSPs to prevent or mitigate.

In particular, Ausgrid seeks to mitigate the risk of any of insurers becoming non-viable by regularly monitoring and reporting by its broker of insurer Standard & Poor (S&P) rating movements. Our minimum acceptable insurer S&P rating is A-. We also keep liability insurance exposure to A- insurers to less than 7.5% and our brokers Aon and Marsh monitor insurer ratings to ensure that any changes are flagged as soon as possible. Our brokers cannot and do not guarantee the security of our insurers.

An excerpt of the Ernst & Young report is provided below. This excerpt demonstrate the prudent risk management framework in place at Ausgrid.

Under the NSW DNSPs' risk management framework:

- The framework uses a Bow-Tie methodology to identify and assess any relevant risks and to understand the nature of these risks (e.g. likelihood, impacts).
- The framework identifies and implements risk controls which are either preventative controls (to lower the chance of the hazardous event happening) or mitigation controls (to lessen the consequences if it does).
- The NSW DNSPs maintain comprehensive insurance arrangements, which are regularly reviewed to align with the Bow-Tie risk assessments. In addition:
  - *The insurance arrangements encompass a robust and thorough renewal and review process*
  - *including forward strategic planning and gathering of updated risk information (including Bow-Tie updates) in order to "sell" their risks appropriately to the global insurance market Advice is obtained from external risk and insurance brokers/consultants (currently Aon and Marsh) and the DNSPs' own insurance specialists to establish the appropriate levels of coverage, implement appropriate insurance market negotiation strategies and to efficiently and effectively manage any claims. The insurance market is cyclical and subject to change, therefore the appropriate levels and types of coverage can vary each year in order to obtain insurance coverage on optimal terms from the market to align with risk treatment strategies.*
  - *The NSW DNSPs take a coordinated approach to insurance with a Group Insurance Committee (GIC) overseeing the insurance renewal and review process. GIC membership is made up of senior group executives and senior executives from each network business, including the Group CFO, Group Executive Network Strategy, Board Secretary, General Managers Finance and Compliance and insurance specialists.*

Moreover, the AER's contention that DNSPs will always be able to assess the viability of an insurer does not take into account how severely impacted the NSW DNSPs were by the unforseen collapse of HIH – Australia's second largest insurer at the time and the largest corporate failure in Australia's history. We submit that even the most prudent risk management approach could not mitigate against such an occurrence, making a pass through a necessary risk management approach to cover such events.

We consider that our approach to nominating this pass through event is reasonable and based on sound reasoning and satisfied the nominated pass through event considerations of the rules. Ausgrid could neither do anything further to prevent an insurer's credit risk event from occurring nor could Ausgrid substantially mitigate the cost impact of such an event.

We also note that the AER's draft decision is inconsistent with its previous approaches or decisions. Notably, the AER has approved a similar pass through event in several of its determinations including for the Victorian DNSP's and also Aurora.

Accordingly, the AER should approve the Insurer's Credit Risk Event as a nominated pass through event having regard to the considerations and evidence described above.

For the reasons above, we have not incorporated the AER's draft decision on this event in our revised proposal. Our revised proposal maintains this event as a nominated pass through events; with the definition of the event described below.

Definitions

The AER accepted our nomination of Insurance cap event, Terrorism event and Natural disaster event as pass through events. As noted above we accept this decision.

In accepting these events as pass through events, the AER however has amended the definitions of these events we proposed in the initial proposal. The AER amended the definitions to include in these definitions the factors that the AER will have regard to when assessing a claim for pass through.

We note our proposed definitions of Insurance cap event and Natural disaster event in the initial proposal also included factors for assessing these pass through events. We adopted these definitions simply to be consistent with the AER's definitions for these events approved in its previous determinations.

The AER's draft determination amended these definitions [insurance cap event, terrorism event and natural disaster event) to include assessment factors.

We have given further consideratoin to the inclusion of assessment factors within the relevant definitions and on further reflectiono we do not agree that these assessment factors should be included in the definitions.

This is because these factors not actually relevant to defining events but rather are relevant to other aspects of the AER's assessment of pass through events. These other aspects relate to (a) the AER's assessment of the approved pass through amounts under 6.6.1 (d) or 6.6.1(g) and (b) the nominated pass through events considerations. We note tha the nominated pass through event considerations are only relevant as criteria for the AER's decision on whether to accept Ausgrid's nominated events as pass through events.

We note that defining the events nominated to be pass through events are necessary to ensure an appropriate description of the event is captured upfront so that when the event has occurred (and the DNSP in its application must be able to demonstrate the event, as defined beforehand, has occurred), the pass through application and assessment process can be triggered. The occurrence of an approved nominated pass through event itself does not automatically mean that the DNSP can pass through the costs to customers. The DNSP must demonstrate, and the AER must determine, that:

a) A positive change event has occurred – that is the pass through event has resulted in material increase in costs.
b) If the AER is satisfied that a positive change event has occurred, the approved pass through amounts, based on the factors in clause 6.6.1(j) of the rules.

Inclusion of the factos in the definition of the event is also inconsistent with rulesfour pre-defined pass through events under the rules. Chapter 10 of the rules defines these four events (regulatory change event, service standard event, tax change event and retailer insolvency event) and none of the definitions include assessment factors.

For all of these reasons Ausgrid submits that assessment factors should be excluded from the definitions and we have revised our proposed definitions accordingly. Our more detailed analysis of the AER's proposed definitions and our reasoning and justification in relation to the individual definitions is set out below.

The AER's amended definition includes:

a) For insurance cap event

Note for the avoidance of doubt, in assessing 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;

ii. The level of insurance that an efficient and prudent NSP would obtain in respect of the event; and

iii. The extent to which a prudent provider could reasonably mitigate the impact of the event.

b) For natural disaster event

Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things:

Whether Ausgrid has insurance against the event:

a. The level of insurance that an efficient and prudent NSP would obtain in respect of the event;

b. Whether a relevant government authority has made a declaration that a natural disaster has occurred; and

c. The extent to which a prudent NSP could reasonably mitigate the impact of the event.

c) For terrorism event

In assessing a terrorism event pass through application, the AER will have regard to, amongst other things:

Whether Ausgrid has insurance against the event:

a. The level of insurance that an efficient and prudent NSP would obtain in respect of the event.

b. Whether a declaration has been made by a relevant government authority that a terrorism event has occurred

c. The extent to which a prudent NSP could reasonably mitigate the impact of the event.

We consider these parts of the definitions are unnecessary as they do not define the events themselves but rather they are factors that go to the assessment of the cost impact of the event or the assessment of whether the event proposed by the NSP should be accepted by the AER as pass through events in its determination. These parts of the AER's amended definitions are already covered in various provisions of the rules dealing with assessment of the costs to be pass through or the acceptance of the event as pass through event.

- Under clause 6.6.1(c)(6) of the rules, an NSP must include in its pass through application evidence of (a) the actual and likely increase in costs and (b) that such costs occur solely as a consequence of a positive change event. Satisfying these requirements would require the NSP to provide details of the insurance policies and the level of insurance.

- Clause 6.6.1(j)(3), (5) and (7) respectively state that:

  (3) In case of a positive change event, the efficiency of the DNSP's decisions and actions in relation to the risk of the positive change event, including whether the DNSP 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 DNSP 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.

  (5) the need to ensure that the DNSP only recovers any actual or likely increment in costs under this paragraph (j) to the extent that such increment is solely as a consequence of a pass through event.

  (7) whether the cosst of the pass through event have already been factored into the calculation of the DNSP'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 DNSP's annual revenue requirement for a subsequent regulatory control period.

In making a determination on the approved pass through amounts, the AER must take into account the above provisions (and others specified under 6.6.1(j)). This exercise would entail the consideration of:

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.

In addition, the nominated pass through event considerations in the rules also require, amongst others, the following consideration in whether the AER approve the events nominated by a DNSP as a pass through event:

(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** (emphasis added).

For the above reasons, Ausgrid considers it unnecessary to include these parts of the AER's definition in either the definition of insurance cap event, natural disaster event and terrorism event or as factors in the assessment of a pass through application. This is simply because these matters are neither needed to define the events nor needed as assessment factors as they have already been covered in the relevant provision of the rules.

The AER also amended Ausgrid's proposed definition of natural disaster event to include a caveat:

Provided the fire, flood or other event was not a consequence of the acts or omissions of the service provider

We consider that this caveat is not necessary in defining the event. This caveat goes to the assessment of the approved pass through amounts and is encapsulated within the rules provision 6.6.1(j)(3). This is a factor the AER must take into account in determining the approved pass through amounts. It may well be the case that the approved pass through amount proposed by a NSP is significantly reduced because of its acts or omission. This fact however does not mean that a natural disaster event has not occurred (a definition issue).

Moreover, the caveat is a departure from the AER's previous approach to these and we consider that are no sound basis for such departure.

The AER also added to the definition of natural disaster event an element which is 'whether a relevant government authority has made a declaration that a natural disaster event has occurred.' We do not support this additional element as it does not enhance or further clarify the definitional boundaries of a 'natural disaster event'. A major fire could occur within Ausgrid's network area that materially increases the costs to Ausgrid of providing direct control services and yet it may not be declared by a relevant government authority as a natural disaster event. Ausgrid has not control or influence over the decision to be made by a relevant government authority and considers that we should not be limited in our ability to pass through the costs of a natural disaster event simply because it has not been declared as a natural disaster event by a relevant government authority (despite all other elements for the pass through of costs under the rules have been satisfied).

For similar reasons, we do not concur with the inclusion of the additional element 'whether a declaration has been made by a relevant government authority that a terrorism event has occurred'. The reference to a relevant government authority is too vague and may lead to unintended exclusion of events which are in fact terrorism event under the definition. It is not clear what may be regarded as 'relevant'. Some legislative provisions maybe directed at triggering insurance caps or other types of relief and are not concerned with whether the has been a terrorism event as such but a certain type of event or an event with certain insurance consequences.

Revised definitions

Following are Ausgrid's revised definitions for insurance cap event, terrorism event, natural disaster event and insurer's credit risk event. For avoidance of doubt, we accept the AER's decision that insurance cap event, terrorism event and natural disaster event are pass through events for the 2015-19 regulatory period. We have only revised the definitions of these events in response to the AER's draft decision and reasons. In relation to insurer's credit risk event, we have not accepted the AER's draft decision to reject this event as a pass through event. Our revised proposal includes this event as a nominated pass through event.

An insurance cap event occurs if:

1. *Ausgrid makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy,*
2. *Ausgrid incurs costs beyond the relevant policy limit, and*
3. *the costs beyond the relevant policy limit materially increase the costs to Ausgrid in providing direct control services.*

For this insurance cap event:

4. *the relevant policy limit is the greater of:*
    a. *Ausgrid'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 Ausgrid was regulated.*

A natural disaster event is defined as:

Any major fire, flood, earthquake or other natural disaster beyond the reasonable control of Ausgrid that occurs during the 2015-19 regulatory control period and materially increases the costs to Ausgrid in providing direct control services.

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% of the DNSP's annual revenue requirement for that regulatory year).

A terrorism event is defined as:

An act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of 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 in providing direct control services.

For completeness, we also include below the definition of insurer's credit risk event we consider the AER should accept in its final decision (both in terms of the event being a nominated pass through event and the corresponding definition).

The insolvency of a nominated insurer of Ausgrid, as a result of which Ausgrid:

i. incurs materially higher or lower costs for insurance premiums than those allowed for in its Distribution Determination; or

ii. in respect of a claim for a risk that would have been insured by Ausgrid's insurer's, is subject to materially higher or lower claim limit or a materially higher or lower deductible than would have applied under that policy.

Application to alternative control services

Our initial proposal also considered that the pass through provisions of the rules to apply to alternative control services. Our reasons in support of this proposal were outlined in section 9 of Attachment 4.13. We noted that our proposed application of pass through provisions is consistent with previous determinations by the AER.

The AER's draft decision appears silent on this aspect of our proposal. We ask that the AER makes a decision consistent with our proposal and its previous determinations for other network service providers in its final determination for Ausgrid.

Connection policy

Ausgrid accepts the AER decision on the connection policy. However we propose some minor clarification to the policy that the AER has approved in its draft determination. We have provided a revised connection policy at Attachment 4.11.

The Ausgrid Connection policy that was approved by the AER in the transitional determination has been in operation for almost 6 months. In that time the Ausgrid network connections team has found two items that need to clarified in the connection policy. In addition, in Section 5 of the connection policy we would like to clarify the metering connection charge.

The proposed changes are listed below:

Section 2.6 shared connection works

The Connection Policy that was submitted in the proposal suggested that some network extensions that have the potential to be shared by other customers would be classed as shared network augmentation and would be funded by Ausgrid.

There are potentially some complex scenarios in built up areas where Ausgrid might contribute to the development instead of creating multiple pioneer schemes. If adopted, this will have minimal change (if any) to connection capex requirements.

The word "will" in Section 2.6 has been changed to "may" so that Ausgrid's contribution is optional.

Section 3.1.5 threshold for large retail customers

After some months using the new connection policy it is recommended that this threshold is not required as any connection applicant over 4MVA falls into the real estate developer definition. After reviewing the connection policy and the AER connection charge guidelines it is clear that this threshold is not needed and so it has been deleted.

There will be no change to connection capex requirements.

Section 5 metering

The description of the metering connection charges has been modified to ensure that the description includes not only the meter but the provisioning costs.

There will be no change to connection capex requirements.

5. Forecast capital expenditure

The AER draft decision did not accept Ausgrid's proposed forecast capital expenditure of $4,421 million ($2013/14) and proposed an alternative estimate of $2,546 million ($2013/14). In this chapter, we set out our revised proposal of $3,756 million ($2013/14) for total capital expenditure.

This revised capital expenditure proposal accounts for changes in inputs, forecast productivity improvements and further improvements in expenditure forecasting that have occurred since the submission of the initial proposal. It also takes into account the input from stakeholders and the comments from the AER and their consultants.

We have presented our revised proposal in a structure that mirrors the approach in the draft decision in order to facilitate a clear assessment of our proposal.

In our initial proposal, we presented our forecast capital expenditure in terms of a series of key plans:

- Area plans;
- Replacement and duty of care plan;
- Distribution capacity plan;
- Reliability investment plan;
- Technology plan;
- Corporate property plan;
- Fleet plan; and
- Other support plan.

These plans were presented inclusive of overheads.

The AER and its consultants relied almost exclusively on the data supplied in response to the regulatory information notice (RIN) in formulating the draft decision. For a range of reasons relating to the limited flexibility and sometimes ambiguous definitions required for the RIN, some conclusions in the draft decision regarding the expenditure Ausgrid forecast for each driver were inaccurate.

In particular, the AER's instructions for completion of the RIN required the addition of a "balancing item" in the summary table to account for the overlaps and absences created by the definitions for each of the component expenditure tables. The draft decision and consultant's reports have noted that this item has been allocated across the main categories of expenditure and sought clarification[111]. The limited RIN categories also meant that some smaller categories of forecast expenditure had to be allocated across other categories, further distorting a clear picture of the proposal. In this revised proposal we have corrected for these anomalies.

PWC independently arrived at the conclusion that care needs to be taken in using RIN data.

> *The Energy Networks Association (ENA) has concluded that much of the historic data provided by its members is unlikely to be sufficiently precise to be reliable for benchmarking purposes. As a consequence of these issues, the results of benchmarking are potentially unreliable or misleading.*

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[111] Draft Decision Attachment 6: Capital Expenditure, p. 6-13 "*We expect Ausgrid to clarify the proposed amount of non-network capex in its revised regulatory proposal and our approach of allocating the balancing item across the capex drivers*".

Further we have identified significant differences between the 13 distributors that raise the risk of inaccurate benchmarking such as: differences in vegetation management practices, related party arrangements and cost allocation methods[112].

In this revised proposal we have corrected for these anomalies to enable us to provide an orderly view of our proposal.

The table below compares the values derived in the draft decision[113] for each of the capital expenditure categories to a corrected view of our initial proposal[114]. This view forms the starting point for consideration of the proposal, the draft decision and comparisons to our revised proposal. We have not included capital contributions as part of our other expenditure categories. This issue is discussed further in the section on connections expenditure. We have also separated the reliability investment component out, as it comprises investments required to meet our regulatory obligations with respect to poor performing feeders, and the constituent projects are typically neither augmentation nor replacement. The draft decision requested Ausgrid to provide further information regarding the correct allocation of the balancing item and other issues[115].

Table 15 – Initial proposal - as presented in the draft decision and corrected view ($ million, 2013/14)

Expenditure category	As shown in draft decision	Corrected data	Difference	%
Replacement & duty of care	3,226.36	2,707.48	518.88	19%
Connections	171.07	193.59	-22.52	-12%
Augmentation	508.96	399.07	109.89	28%
Reliability	Allocated to Augmentation	27.74	-27.74	-100%
Non-network	307.64	333.43	-25.79	-8%
Overheads	729.23	759.68	-30.45	-4%
Capital contributions	Allocated in above categories	522.29		
Total Expenditure	4,943.27	4,943.27		

Note: Numbers may not add due to rounding.

Our forecast for capital expenditure is presented as components classified by driver and in direct costs only, with overheads identified in a separate line item. A cross reference table is provided in section 5.11 to enable reconciliation of the driver view used in this revised proposal and the plan view used in our initial proposal.

5.1 Revised capital expenditure proposal

Ausgrid's revised proposal forecasts capital expenditure for standard control services totalling $3,756 million ($2013/14). This is 15% lower than our initial proposal of May 2014.

This revised forecast is based on changes to our plans arising from updated planning, improved labour and delivery efficiency expectations and improved processes since the initial proposal was submitted and on adjustments made to our approach in response to feedback from the draft decision and from stakeholders.

The key variations are:

- Lower augmentation expenditure in response to lower forecast demand, and improvements in our high voltage distribution expenditure forecasting models;
- Lower replacement expenditure arising from application of cost benefit analysis techniques to major cable and switchgear renewal projects;

[112] Attachment 1.10 - PWC - Independent Expert Advice on appropriateness of RIN data for benchmarking comparisons, Jan 2015, p. 5

[113] AER Draft decision Ausgrid distribution determination - Ausgrid 2014 - Consolidated Capex Forecast model - November 2014.xlsx

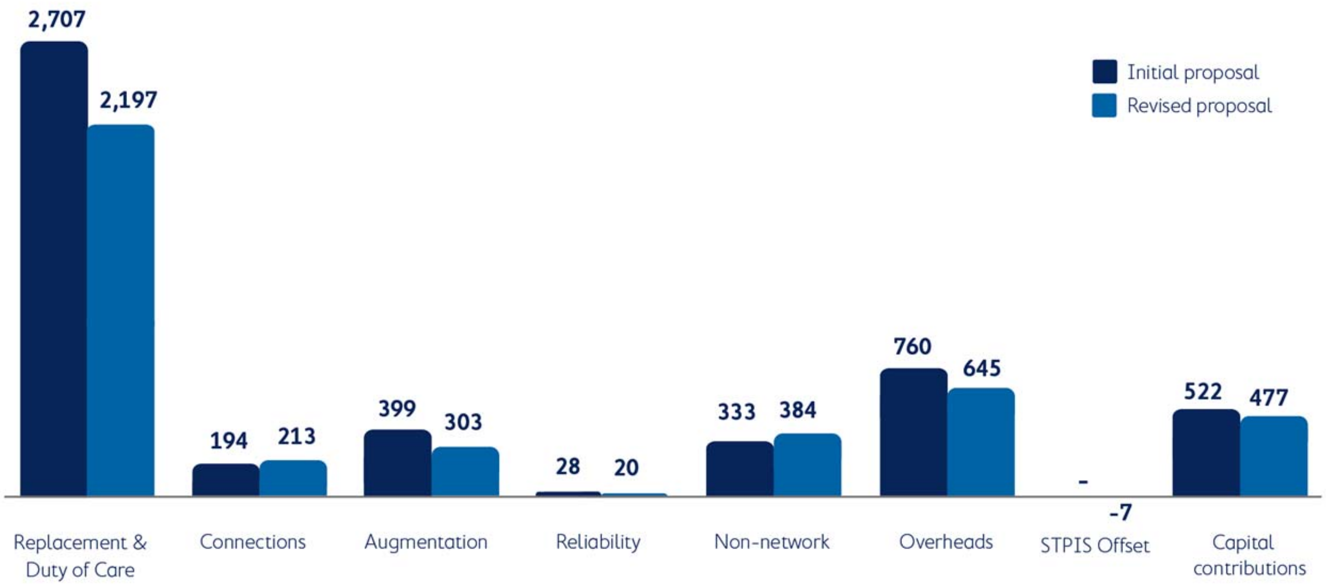
[114] Based on 20141210 RIN amendments for direct and indirect costs - amendment.xlsx provided to AER 20 December 2014

[115] Draft Decision Attachment 6: Capital Expenditure, p. 6-13

- Lower replacement expenditure arising mainly from improved segmentation within replacement and duty of care program categories and improved understanding of consequences arising from further development of our risk cost assessment approach;
- Top-down allocation of efficiency improvements arising from project scope efficiencies for major projects currently in the planning phase and medium term unit cost improvements from current efficiency programs; and
- Recognition of offsets to our reliability compliance program from forecast marginal STPIS revenues.

These reductions are offset by a small increase in the connections expenditure forecast to recognise the delayed impact of the new connection policy, and a relocation of non-network SCADA and network control expenditure from the network to the non-network category. The results are shown graphically in the chart below.

Figure 8 – Revised capital expenditure proposal by driver ($ million, 2013/14)



Our revised capital expenditure proposal is shown in the table below, which also includes our initial proposal and the draft decision for comparison.

Table 16 – Revised capital expenditure proposal ($ million, 2013/14) (excludes capital contributions)

Plan	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Revised proposal	766.2	864.3	819.0	699.9	606.1	3,755.6
Initial proposal	1011.5	984.9	856.8	814.0	753.8	4,421.0
Draft decision	591.0	544.1	481.0	473.3	457.0	2,546.4

Note: Numbers may not add due to rounding.

At the driver category level, the changes are:

Table 17 – Revised capital expenditure proposal compared to initial proposal ($ million, 2013/14)

	Initial proposal	Revised proposal	Difference	%
Replacement & duty of care	2,707	2,197	-510	-18.8%
Connections	194	213	19	9.8%
Augmentation	399	303	-96	-24.1%
Reliability	28	20	-8	-28.6%
Non-network	333	384	51	15.3%
Overheads	760	645	-115	-15.1%
STPIS offset	0	-7	-7	
Total expenditure	**4,421**	**3,756**	**-665**	**-15.0%**
Capital contributions	522	477	-45	-8.6%

Note: Numbers may not add due to rounding.

In the following sections we have provided responses to the observations, clarification requests and conclusions of the draft decision. We have explained our revised expenditure forecast in each category and applied top down validation approaches that are similar to those used by the AER and its consultants in the draft decision. In addition to the detail of the plans, these cross checks serve to demonstrate that our revised capital expenditure forecast is a reasonable estimate of the expenditure requirements of a prudent and efficient network operator.

Ausgrid's revised proposal addresses the capital expenditure criteria, being:

(1) the efficient costs of achieving the capital expenditure objectives;

(2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

5.2 Overall response to draft capital expenditure decision

Ausgrid does not accept the draft decision for capital expenditure. Indeed to do so would jeopardise our ability to manage the network in a way that would maintain safety, reliability and efficiency at prudent levels that would meet community expectations. Further information is provided in Chapter 1 and referenced Attachments, which identify in particular the safety and reliability consequences that would be likely outcomes from the implementation of the draft decision. The application of top-down estimation and benchmarking is appropriate only as a validation approach and to identify areas for further investigation and review. Ausgrid does not accept its use to determine a substitute capital expenditure allowance. For example, R2A's analysis indicated that:

> *If Ausgrid were to operate within the constraints of the AER's draft determination, then in the short term, the number of safety incidents, especially to employees, is expected to spike due to the change in safety culture associated with this scale of staff loss. In the longer term, this analysis indicates that for the foreseeable threats to members of the public considered in this review, an increase of around 3.4 per annum in the fatality rate from network hazards would most likely occur. In addition, the likelihood of the Ausgrid network starting a catastrophic bushfire (meaning 100 fatalities and 1,000 houses lost) more than doubles, assuming existing precautions (especially vegetation clearance and asset condition inspection effectiveness) remain unaffected by the proposed revenue reductions.*[116]

At the highest level, the draft decision fails to engage adequately or appropriately with the substance of our capital expenditure proposal. Instead, the AER and its consultants have preferred to focus on developing their own competing estimates based on data provided in response to the RIN issued prior to submission of the initial proposal.

[116] Attachment 1.13 - R2A: Asset/System Failure Safety Risk Assessment, p. 4

This has resulted in a significant number of cases of data being used for purposes it was not suited for, misinterpretation of the underlying meaning of the data provided, and the necessity of making extensive assumptions to make the data fit the analytical framework, rather than the other way around. It is unfortunate that more time and effort was not spent on responding to the considerable weight of material provided in our submission. Even in the cases where reference was made to some of the documentation provided, it was too often misread, misunderstood or misinterpreted.

In this revised proposal, we have provided detailed responses to the components of draft decision driver by driver.

At the total expenditure level, the draft decision identified three aspects of Ausgrid's forecast methodology as key concerns:

- The absence of top-down review of bottom up estimates;
- Excessively conservative risk assessment in cost benefit analysis; and
- Lack of delivery strategy.

Each of these issues has been considered in formulating our revised proposal and discussed within the appropriate section of this document.

Governance framework

The first two of these issues cannot be addressed without a discussion of Ausgrid's investment governance framework. While the commentary about conservative risk assessments applies mainly to the program and project level assessments, any discussion about risk assessment must include the high-level risk assessment embodied in our top-down investment prioritisation process.

The draft decision states:

> *Ausgrid's forecasting methodology applies a bottom-up build (or bottom-up assessment) to estimate the forecast expenditure for all its capex categories (except for information and communications technology). It does not involve applying a top-down assessment*[117].

Ausgrid applies several levels of top-down assessment in various parts of its investment planning process, but the most visible and formal is through the board level gate 1 investment portfolio approval process. The existence of this top-down process is acknowledged by the AER's own consultants EMCa, who devote a whole section of their report to their concerns about the top-down assessment Ausgrid's Board applied in their report.

EMCa have been critical of the top-down program adjustments made by the NNSW board, stating:

> *…the fact that a 24% capex reduction could be made without having a material impact on network risk, and without an apparent asset management-based justification for the reduction, is a strong indicator that Ausgrid's forecasting processes have overestimated required repex*[118].

Ausgrid believes these concerns stem from a misinterpretation of the information provided in our proposal and at the on-site meeting and are based on an erroneous understanding of the planning and investment governance process.

The governance process

Our governance and risk management framework was explained in our initial proposal and in the accompanying evidence. We have a prudent and robust process in place to ensure that our capital expenditure program represents a reasonable estimate of the lowest cost solution to address a genuine network need, consistent with the capital expenditure objectives.

The key stages of our governance process, as outlined to the AER and its consultant, include:

- Governance around the policies and standards which drive key triggers for investment with both independent and peer review and endorsement of the technical and risk triggers for investments.
- Effective input early in the process with the provision of long term (forward 5 to 10 years) strategies and plans to the board.
- Annual development by the business of approval of the risk prioritised investment portfolio by the board (gate 1). Effective risk based prioritisation enables the Board to make an informed decision based on its risk appetite with an understanding of the risk versus expenditure position rather than uninformed changes to the portfolio.
- Preliminary individual project / program approval outlining the need and the options to address it (gate 2). Approval is by the delegated authority and all projects and programs with a total estimated investment above $5 million are subject to

[117] AER draft decision – Attachment 6: Capital expenditure, p. 6-20

[118] EMCa – Review of proposed replacement capex in Ausgrid's regulatory proposal – October 2014, p.12

independent and peer review as part of the governance process. The review tests the need for the investment and the prudency of the proposed options.

- When project design is complete, and the most efficient delivery model has been determined, final project approval is required (gate 3). As with the preliminary approval all investments above $5 million are tested through an independent and peer review prior to approval.

Risk based investment prioritisation is one of the key stages (gate 1) in our governance process. The ability to prioritise investments is an important factor in development of the portfolio investment plan. The methodology we have used for prioritisation has been developed to be consistent, efficient and transparent in order to articulate the risk outcome associated with a particular investment scenario. The current risk topic areas used to prioritise the portfolio include:

- Public safety, environmental or regulatory impact;
- Network initiated fire;
- WH&S (employee);
- Network condition;
- Community impact (reputation);[119]
- Network reliability; and
- Network capacity.

It important to recognise that investment planning is undertaken concurrently with the development and risk assessment of the overall portfolio. Planners were required to undertake risk assessments for each program using the CASH methodology, and to include alternative program timing scenarios (effectively alternate programs) as part of finalising the proposed program. Our expenditure forecast was constructed and progressively refined over a period of time.

Delivery risks and constraints are also reviewed and where required incorporated into the plan and sensitivity and economic analysis is conducted with consideration to the viability of the capital structure under a number of scenarios.

The investment governance committees review the resulting portfolio and provide an initial top-down challenge process. This process tests the projects and programs, both for consistency of risk prioritisation and for deferral risk.

We recognise that the factors driving investments and risk can change over time – for example due to changes in demand, failure modes, asset deterioration, delivery costs, standards and policies. As a result a formal change control process is in place to provide governance and transparency for any changes to the Board approved portfolio and risk position.

The 2013 gate 1 approval

2013 was the first time we had utilised the CASH methodology to present a risk prioritised investment portfolio to the board. This had been preceded by several papers discussing the principles of the model and gaining board endorsement for the process.

When the final portfolio was presented to the board, it was accompanied by a clear recommendation that the required portfolio should be substantially lower than that projected as being required in the 2012 SCI[120]. In Ausgrid's case, the 2012 SCI forecast totalled $5,882 million (nominal). As a result of planning reviews and adjustments, the forecast requirement was reduced due to lower demand forecasts, revised risk assessments and better targeting of replacement programs, a change to metering strategy and the impacts of a revised connection policy. The Ausgrid capital expenditure portfolio[121] presented to the board for Ausgrid's substantive regulatory proposal recommended an appropriate risk balanced level between $4,459 million and $4,681 million, with operating cost trade-off implications for lower recommended levels of investment, and risk implications of levels lower than this. They were presented with full visibility of the risk assessment process and examples of projects that ranked above and below key expenditure levels.

The upper bound of recommended investment for Ausgrid was already 20% lower than the 2012 SCI forecast. The Board determined a final amount which, in Ausgrid's case was approximately 4% below the upper recommended level.

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[119] Reputation is a new topic area included as a result of an independent review into our prioritisation process and tool. This topic has been included in the prioritisation process used for the capex forecast in this revised proposal.

[120] Statement of Corporate Intent.

[121] Network capital including metering, public lighting, ancillary services and overheads

This is why Ausgrid has stated that the board approved replacement capital expenditure level does not have a material impact on network risk. The board did not make an uninformed 24% random cut to our recommended expenditure. They approved a forecast expenditure that was 24% lower than the 2012 forecast for the five year period 2014-19, but their decision was based on information provided on risk assessment, opex / capex trade-offs and was within a range that arose from our underlying planning and risk assessment processes.

Independent review

Subsequent to the submission of our regulatory proposal an independent review was conducted on the risk based prioritisation process. Evans and Peck, who conducted the review, noted that there were a number of very significant positive aspects to our process and also provided a number of improvement opportunities. The majority of these opportunities have been incorporated in the expenditure forecast supporting the revised proposal.

Advisian (formerly Evans and Peck) have subsequently conducted a post implementation review (see appendix A of Attachment 5.12) of the changes implemented to the prioritisation process and have confirmed that the changes provide for significantly increased alignment with the common risk matrix, greater differentiation on risk scores, improved focus on top risks at board level and a greater level of documentation and reasoning behind risk scoring.

Jacobs have also disagreed with EMCa's interpretation in their review:

> *However, based on the review Jacobs considers the AER's position to be inaccurate. Jacobs considers the NSW DNSP's approach clearly demonstrates a considered top-down assessment of their Capex forecasts in reaching their final expenditure proposal. As such, the AER's findings would not appear to justify discounting the Capex forecasting methodologies of the NSW DNSPs and substituting them with the AER's methodology….*
>
> *Jacobs considers that the processes employed by the NSW DNSPs broadly address these criteria. Conversely, Jacobs notes that the approach substituted by the AER does not meet its own stated criteria for what a top-down assessment "should" include.*
>
> *The AER has also concluded that the risk assessments do not adequately justify the priority and timing of the Capex forecasts. However, it appears that this conclusion has been reached because the CASH/PIP process was not properly understood. In Jacobs' view the CASH/PIP top down assessment clearly provides adequate granularity to inform the prioritisation and scheduling of the associated capital works programmes. …. The AER appears to be taking a position on expenditure without apposite consideration of the risk profiles associated with the varying levels of expenditure. In particular, the AER's approach does not appear to consider "risk level metrics [as] key elements of capex drivers" within its substituted Capex forecast approach.*[122]

Ausgrid believes its formal top-down review process exhibits the key characteristics of an effective assessment and decision process that supports our contention that our capital expenditure forecast is a reasonable forecast of the expenditures that would be required by a prudent and efficient operator.

For the overall assessment of our capital expenditure proposal, the AER applied its own versions of top down analysis. These comprised comparative benchmarking and trend analysis.

Benchmarking

In its draft decision, the AER indicated that it *"…looked at a number of historical metrics of Ausgrid's capex performance against that of other DNSPs in the NEM*" and that these metrics were based on "*…outputs of the annual benchmarking report and other analysis undertaken using data provided by the DNSPs for the annual benchmarking report*"[123]. This includes;

- relative partial and multilateral total factor productivity (MTFP) performance;
- capex and RAB per customer and maximum demand; and
- historic capex trend(s).

In relation to partial and MTFP productivity measures, the analysis is superficial and not credible. Despite concerns regarding Ausgrid's significant increase in capital expenditure in the previous regulatory period, the MTFP results indicate that total and capital productivity measures have not varied significantly over the previous regulatory period. Indeed, the productivity measure and relative position of each business has hardly changed over the period analysed, despite many going through similarly significant

[122] Attachment 1.16- Jacobs - Review of Prudency etc, p. 26-27

[123] AER draft decision – Attachment 6: Capital Expenditure, p. 6-23

changes in their capital expenditure profile. This suggests the measure is indicating underlying differences between the businesses, not productivity performance relating to capital expenditure.

Consultants Frontier Economics' independent review found that differences between businesses (heterogeneity), rather than inefficiency is highly likely to explain benchmarking differences.

> *In contrast to Economic Insights (EI)[124], given the material differences in cost structure we have found, plus the failure to ensure data consistency across and within countries in the sample, we consider it highly likely that the majority of the remaining variation is in fact explained by latent heterogeneity.*[125]

In addition, in the case of the so-called 'frontier efficiency firms' such as Citipower and Powercor that have the same owner, asset management policies, corporate support structures and shared services businesses, there is more than 60% difference in capital productivity and more than 35% difference in total factor productivity. It is clear that these measures are meaningless unless they either take account of key underlying differences in the various network businesses or that comparisons are restricted to similar network businesses.

The capital input measure is based on RABs and depreciation. RABs were set at different times and under different jurisdictional arrangements relating to tax depreciation and are not a comparable measure of capital inputs. This approach can also be impacted by variations in approach to the treatment of overheads. In addition, the AER[126] itself notes that depreciation will be impacted to the extent that fully depreciated assets are still being utilised. This is illustrated by comparing depreciation as a proportion of RAB for the various businesses. For the majority of businesses, this ratio is above 5%. In the case of Ausgrid, this ratio is 3.4%. This supports the contention that Ausgrid's asset base contains large numbers of assets that are already beyond their standard life.

Capex per customer or maximum demand are partial measures at a point in time that do not account for differences in the investment cycle of the respective businesses. A business that is in a period of major replacement or refurbishment will inevitably have high levels of capex. In the case of RAB per customer or maximum demand, this measure is impacted by the significant differences in the way in which RAB's were determined as discussed above.

Jacobs identify this hazard in their review. They note:

> *RAB is not a 'perfect' denominator to use in cross DNSP comparison because the RAB's of Australian DNSPs were established at different points in time using different unit rate costs, and using asset quantity data that was not always accurate.*
>
> *As a particular DNSPs 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 to be inefficient in respect of Repex). In fact it is an indicator that the ageing system requires more Repex (not less) to control the deteriorating age profile and declining asset condition"*[127]

In summary, the approach to benchmarking is unsuited to providing any meaningful input to the assessment of the prudency and efficiency of the capital expenditure forecast as required under the capital expenditure criteria.

Huegin have noted:

> *The particular issue of measurement of physical assets is less material… however the importance of network design should still be recognised as an environmental variable for opex.*[128]

and

> *In our view the analysis that the AER has relied upon in recommending adjustments to NSW and ACT expenditure forecasts based on benchmarking is too limited to facilitate meaningful conclusions.*

These issues are more fully explored in the benchmarking and operating expenditure sections and supporting Attachments referenced within, which include reports by Huegin, Advisian, PWC, Frontier Economics, PEG and Cambridge Economic Policy Associates.

[124] AER draft decision consultant report- Economic Insights – Economic benchmarking assessment of operating expenditure for NSW and ACT Electricity DNSPs - 17 Nov 2014

[125] Attachment 1.05, p. ix

[126] Electricity distribution network service providers - Annual Benchmarking Report (AER, November 2014), p. 25

[127] Attachment 5.08 – Jacobs - Review of AER Draft Decision - Repex, p.ix

[128] Attachment 1.06, p. 35 & 38.

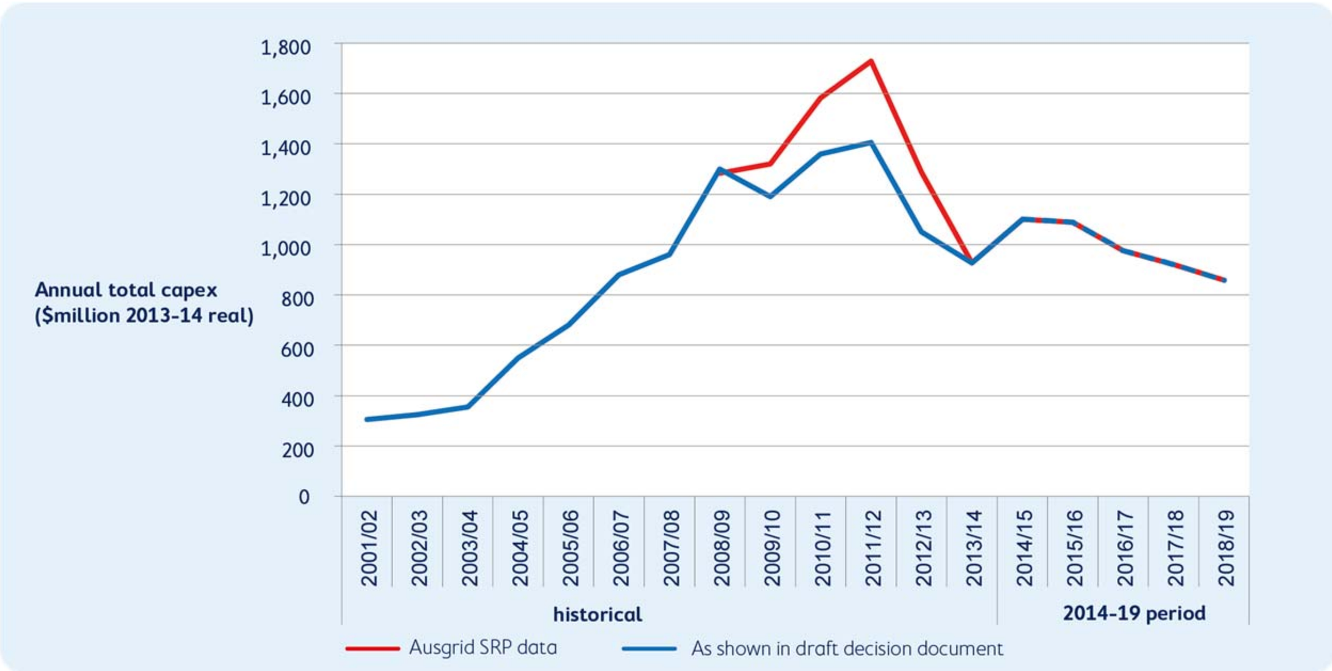
Trend analysis and licence conditions

The AER has also made use of historic trends analysis. This analysis needs to be carefully interpreted. Whilst a 15 year period may appear to be an adequate period of analysis, in the context of a sector with asset lives of 45-60 years, this period of analysis is inadequate, particularly when a significant proportion of assets are approaching end of life.

The draft decision contains a chart of historical capital expenditure[129] that is repeated in Attachment 6[130]. The values in the chart do not agree with the information provided in our submission and in the RIN requested by the AER. The draft decision quotes a series of historical sources for the data, but it appears that there has been no checking to ensure that the data was compiled on a comparable basis. The data we provided was prepared using the same assumptions and definitions. The chart below superimposes the data provided with our submission over the chart in the draft decision.

Clearly the draft decision has understated the historical expenditure, or overstated Ausgrid's proposed expenditure, most likely due to the data being compiled for different purposes and with different assumptions or definitions. This alone would call into question the validity of any conclusion drawn from such data. However it is also the case that historical capital spend on a network is not a useful predictor of future needs. Jacobs, in reviewing the approach in the draft decision with respect to replacement expenditure stated "*Simply put, future requirements for sustainable replacement and refurbishment expenditure cannot be predicted by past trends and averages of actual expenditure.*"[131] This issue is discussed further in the section on replacement expenditure below.

Figure 9 – Ausgrid gross capital expenditure 2001-2019



The draft decision then goes further in claiming "*A key driver of capex from 2005 was the NSW licence conditions around design standards. These were removed in July 2014*"[132]. It further claims that the removal of these requirements in July 2014 "*is likely one of the key reasons for the reduction in capex proposed by Ausgrid for the 2014–2019 regulatory control period. However, it has not reduced to the levels that existed prior to the licence conditions being introduced. Given the recent changes in licence conditions, we consider the period prior to 2005 should be the benchmark for assessing the level of capex for the 2009–2014 regulatory control period*"[133].

[129] AER draft decision – Overview, Figure 8.3, p. 50

[130] AER draft decision – Attachment 6: Capital expenditure, Figure 6.8, p. 6-29

[131] Attachment 5.08 – Jacobs - Review of AER Draft Decision - Repex, p. ix

[132] AER draft decision – Attachment 6: Capital expenditure, p. 6-29

[133] AER draft decision – Attachment 6: Capital expenditure, p. 6-30

In support of its view, the draft decision references a quote from AEMO which was submitted as part of the AEMC review of licence conditions for the NSW government in 2012. The draft decision omits to mention that the AEMC's final report discredited this claim.[134]

The design standards in licence conditions relate primarily to augmentation expenditure. In our proposal we noted that we expected the changes would provide additional flexibility in how we would deal with future load growth. However we also identified the change to the demand forecast as the main driver of changes in this area. This issue is explored further in our section on augmentation expenditure below.

The draft decision contradicts its line of argument regarding the licence conditions when it notes, in regard to another chart showing the breakdown of historical expenditure, "*This shows that replacement expenditure (repex) has increased and remains relatively high compared with the reductions made in other areas of capex. The large reduction in augmentation capex (augex) is to be expected due to the expected slow growth in peak demand and the removal of the regulatory obligations on planning standards*"[135]. If replacement expenditure is the main driver of ongoing expenditure, and augmentation has suffered a large reduction, then surely the conclusion that "*Given the recent changes in licence conditions, we consider the period prior to 2005 should be the benchmark for assessing the level of capex*[136]" is unsound.

It is also relevant to remake the point from our submission that the reason the licence conditions came to exist was to remedy the loss of supply security that had been allowed to diminish during a prolonged period of under-funding and consequent constraint on prudent investment. Having restored those more prudent levels, there would be no need for further "backlog" expenditure in the next period. With the prospect of much lower forecast demand growth, Ausgrid's need for capacity augmentation is expected to be very low – with or without the licence conditions.

The draft decision then goes on to consider expenditures at the category level, and draw further conclusions. In this case, there are also data issues, but they are not as significant. The data used for this trend analysis is drawn from the RIN data supplied for the initial proposal. The draft decision makes the observation that "*replacement expenditure (repex) has increased and remains relatively high compared with the reductions made in other areas of capex*"[137].

The average replacement expenditure in our initial proposal is higher than our actual expenditure in the period 2009-14. However, the difference in the average annual expenditure is less than 1% (real, based on the data in our RIN). An increase of this level should not be considered grounds for concern. After correction (as noted at the beginning of the chapter), there is a small reduction from 2009-14 actuals to 2014-19 forecast. Even if there were a significant increase, it is not reasonable that a trend analysis that only considered detailed data starting from 2009-10 could provide any support for the conclusion that "*the period prior to 2005 should be the benchmark for assessing the level of capex for the 2009–2014 regulatory control period*[138]".

Revised capital expenditure proposal

Our revised capital expenditure proposal is 15% lower than our initial proposal.

The level of our forecast augmentation expenditure is at historic lows, with no planned major projects driven by load growth and much lower levels of expenditure at all voltage levels of the network. The impact of our reduced demand forecast, which was produced after the initial proposal was submitted, is the main driver. Flexibility from the changes to licence conditions has been factored in, but with such a low level of spend already, the marginal additional impact is small.

Our replacement expenditure proposal is now a decrease compared to the previous period. This is the result of newly developed risk-cost benefit analysis applied to major renewal projects, and a review of all proactive replacement programs involving a revised approach to the quantification of risk consequences.

High level trend analysis of the revised proposal shows that gross capital expenditure continues to decline steadily since the peak of 2011/12, with expenditure on this basis 38% lower than in the previous period. In our view this represents a return to a long-term sustainable level of expenditure, having made significant inroads into restoring the supply security and arresting the decline in health of the network over the previous period.

This confirms our view that the proposal represents a reasonable estimate of:

(1) the efficient costs of achieving the capital expenditure objectives;

[134] AEMC, Final report – NSW Workstream, Review of Distribution Reliability Outcomes and Standards, 31 August 2012, p. iv

[135] AER draft decision – Overview, Figure 8.3, p. 50

[136] AER draft decision – Attachment 6: Capital expenditure, p. 6-30

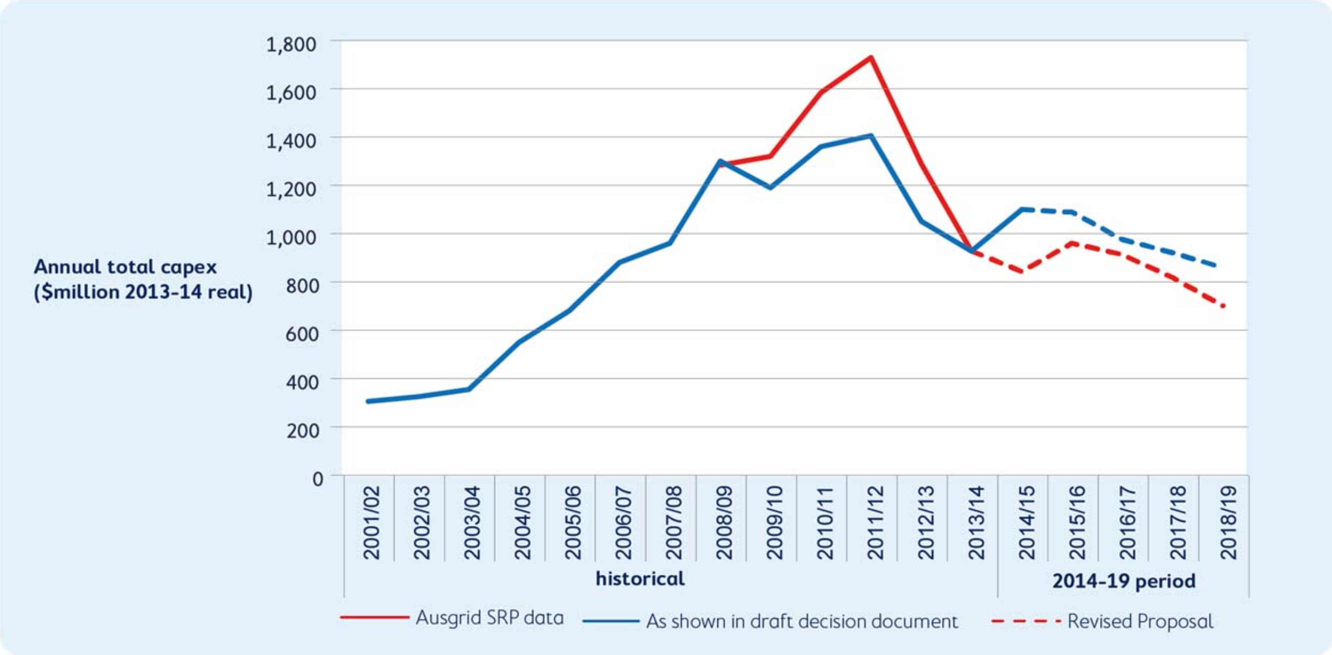
[137] AER draft decision – Overview, Figure 8.3, p. 50

[138] AER draft decision – Attachment 6: Capital expenditure, p. 6-30

(2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

Figure 10 – Ausgrid gross capital expenditure 2001-2019 – Revised Proposal



5.3 Augmentation expenditure

The draft decision

The draft decision identified Ausgrid's forecast augmentation expenditure as $509 million, excluding overheads. The draft decision did not accept this forecast and instead included an amount of $376.4 million for augmentation expenditure. This included an approximately 12% reduction to account for the changes in demand forecasts from 2013 to 2014. It also included a further 15% to account for the removal of deterministic planning criteria from Ausgrid's Distribution Licence Conditions on 1 July 2014 and the resulting flexibility to apply risk based cost benefit analysis to augmentation expenditure decisions.

Ausgrid's response

Ausgrid agrees that the principles identified in the draft decision should apply to the assessment of the augmentation capital expenditure proposal. However we disagree with the outcome in the draft decision. The external review on which the draft decision relies is extremely brief and high level. Even when combined with the in-house analysis by AER staff, we do not believe this constitutes a sufficiently robust base for substitution of an alternative estimate of augmentation capital expenditure requirements.

We have prepared a revised proposal that effectively considers both of the effects identified in the draft decision and takes into account differences in both demand forecasts and planning methodology since the initial proposal was submitted.

Ausgrid's initial proposal

Augmentation expenditure in Ausgrid's initial proposal consisted of elements of the area plans and the distribution capacity plan. Combined, these elements add up to a forecast augmentation expenditure total of $400 million ($2013/14, direct costs). This amount does not include the $28.5 million identified in the reliability investment plan, which was included under the augmentation category of the RIN. We address this component separately later in the revised proposal.

The reason the draft decision calculated $509 million for this expenditure category is due to a range of issues with the conversion of our proposed expenditure into the RIN data format and the subsequent attempts in the draft decision to reconcile these differences. Our expenditure forecasts in our initial proposal were all presented inclusive of all overheads, and this created issues when the AER needed to evaluate the direct costs separately to the associated overheads. Other problems in calculating the direct costs from our RIN data included the way in which the balancing item in the RIN data was allocated back into the expenditure categories; the implied treatment of capital contributions; the inclusion of reliability expenditure (which is not augmentation); corrections to errors and misunderstandings in the non-network expenditure category; and the approach to netting out overheads.

Ausgrid provided corrected RIN data to the AER on 12 December 2014 that resolved the majority of these issues and presented the categories of expenditure in direct cost terms. It is important to recognise that the proposed augmentation expenditure in our initial proposal was already some $100 million less than the input used in the analysis for the draft decision.

Change in forecast demand

The draft decision correctly identified that there would be an expected reduction in the need for augmentation because of the changes in the peak demand forecast. However, the top-down adjustment based on ratcheted demand used in the draft decision is at best broadly indicative of direction and not robust for calculation of quantum.

Firstly, the approach used failed to account for the significant proportion of the forecast augmentation expenditure that was for committed projects that could not reasonably be cancelled even if circumstances had changed. WorleyParsons recognised this as appropriate in their review[139]. Instead, the AER's top-down adjustment was applied to all HV distribution capacity investment, even the $32.5 million that was specifically identified as "works in progress".

Secondly, in our initial proposal we made the point that augmentation expenditure continued to be required to meet pockets of demand growth in localised areas even when higher level growth indicators suggest low or flat net growth[140]. This is especially the case in Ausgrid's service territory, where infill development of established areas is the dominant growth driver. The draft decision recognised this as a legitimate issue[141]. The top-down adjustment based on ratcheted demand at zone substation level makes no allowance for this phenomenon and is therefore likely to overestimate the reduction in required expenditure, especially in the HV distribution network where it was applied.

On this basis the approach used in the draft decision to adjust augmentation expenditure is likely to have significantly over-estimated the effect of changes in demand forecasts on augmentation expenditure.

For our revised proposal, we have reviewed all relevant planning elements based on the latest demand forecasts through a full review of the Area Plans, and re-running the models that underpin the Distribution Capacity Plan. This approach ensures our proposal reflects:

(1) the efficient costs of achieving the capital expenditure objectives;

(2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

Change in planning standards

The draft decision claimed that WorleyParsons found Ausgrid had *"developed its augex forecast primarily on the licence conditions applying in the 2009-2014 regulatory control period*[142]". The WorleyParsons report in fact acknowledges (in section 3.4.4) that Ausgrid did implement an interim planning standard on 1 July 2014 to reflect the expectation that new planning standards would have greater flexibility with regard to the timing of high cost investments in particular. It is important to recognise that re-planning a network as substantial as Ausgrid's takes some time, and the majority of the planning effort had to be undertaken prior to the government's announcements in January 2014[143] regarding the future form of the licence conditions. Ausgrid was therefore required to make changes to its planning approach for the initial proposal in anticipation of unknown changes to the licence conditions.

The key change implemented was a change to the approach to subtransmission underground feeders. The approach was explained in the area plan overview[144] attached to the initial proposal and acknowledged by WorleyParsons. This approach arose from the work done for the AEMC review of planning standards for the NSW Government undertaken in mid-2012. In the course of testing a range of potential future scenarios, we identified that the only changes that would have material impacts in the near (5-year) term would be from changes to the timing of subtransmission underground feeder projects. The development of the area plan forecasts for the initial proposal used this less stringent deterministic approach. This was intended to reflect the likelihood that there was a high probability of changes to the licence conditions that would provide greater flexibility in decision making. As a result of this change and the reduction in forecast demand growth, the 2013 area plan review deferred all major (>$25m) growth related projects beyond 2019.

The area plan augmentation expenditure forecast included in the initial proposal was $81 million ($2013/14, direct cost). Of this total, $28 million was for completion of in-flight projects (more than 80% complete) that it would not be prudent to discontinue[145]. Excluding these amounts, the planned augmentation component of the area plans was only $41 million (51%).

It is important to note that the approach taken by Networks NSW in reviewing operational planning standards was considered in the light of the materiality of the decisions to be made on augmentation expenditure over the near term. We recognised that the

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[139] WorleyParson – Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014-19 – 17 Nov 2014, section 3.4.1

[140] Ausgrid regulatory proposal May 2014, p. 34

[141] AER draft decision – Attachment 6: Capital Expenditure, p. 6-41

[142] AER draft decision – Attachment 6: Capital Expenditure, p. 6-41

[143] Ausgrid regulatory proposal May 2014, attachmnent 5.06

[144] Ausgrid regulatory proposal May 2014, Attachment 5.23, section 2.2

[145] WorleyParsons endorsed this position in section 3.4.1 of their report

removal of deterministic planning standards left a significant task to be undertaken to develop, test and decide on new planning standards and methodologies. Having identified that lower demand forecasts meant that few augmentation projects would be initiated in the near term, there was little risk in adopting an interim approach that involved specific reviews of high value projects. It is these high-value individual project reviews that WorleyParsons refer to in their review of Endeavour Energy's approach.[146] This is a prudent approach to managing the uncertainty arising from the removal of deterministic planning criteria. In Ausgrid's case, the adoption of the modified criteria for underground subtransmission cables and the lower demand forecast meant that there were no high value augmentation projects planned prior to 2019, and therefore no projects to subject to specific cost benefit reviews.

While WorleyParsons correctly observed that changes to planning standards for operational planning for HV distribution had not been fully implemented at that time, this had no bearing on the expenditure forecast as the HV segment is forecast using a modelling approach (not bottom up planning decisions).

Ausgrid projected its need for augmentation expenditure in the HV distribution network using a model that has been developed over several years. It assumes levels of feeder utilisation that are based on the requirements of the pre-existing licence conditions. However, we also realised that the model was developed in the context of continuing positive growth and failed to take proper account of the impact of the diversity between growth rates on individual feeders.

The model assumes that all feeders in a zone exhibit the same growth rate (the zone average). As average zone growth rates have slowed, it has become obvious that this approach does not account for the phenomenon of growth appearing in pockets that has become evident at Ausgrid.

For example, consider a zone substation with twenty feeders feeding an area of perhaps 15km^2. Demand in one local part of that zone might be growing at 5% per annum. Over the same period, another geographically separate part of the zone might be facing reducing demand. The zone might have a low or zero overall growth rate, but investment is still required to deal with the growing region of the zone. Further, because the pockets of growth tend to be driven by local factors, it is likely that all nearby feeders in that area will also be facing growth, so the spare capacity is in the wrong place to assist in offsetting the growth.

We recognised that the model assumption of uniform feeder growth was conservative and likely to under-forecast augmentation expenditure[147]. We chose not to re-develop the model to account for this on the basis that the flexibility arising from the removal of licence conditions would compensate. Note that it is this assumption of uniform growth that we were referring to in discussions with WorleyParsons[148], which it appears they may have incorrectly interpreted.

In summary, the Area Plan component of the augmentation expenditure forecast was comprised primarily of in-flight projects. It would not be prudent or in the long-term interests of customers to forego the benefits of these projects having incurred most of the cost (a view Worley parsons endorsed[149]). Changes to planning standards would have no impact on this expenditure because it had already been factored into the 2013 review. The HV distribution capacity expenditure forecast was based on a top down modelling approach which we recognised under-forecast augmentation requirements in a low growth environment, and the overall distribution augmentation forecast also contained a substantial element of in-flight projects. In this situation, the application of a flat percentage reduction across all augmentation expenditure was inappropriate.
The draft decision applied a 15% reduction to all augmentation expenditure. The review by WorleyParsons concluded only that:

> *The application of risk based cost benefit analysis assessment techniques to projected programs of work would likely result in further reductions in projected expenditure*."[150]

WorleyParsons did not offer guidance as to the likely size of the reduction.

Instead the draft decision relies on comments by WorleyParsons in relation to Endeavour Energy to establish a level. The draft decision says:

> *We consider that Ausgrid could efficiently make a 15 % reduction to its augex projects by applying risk based cost benefit analysis assessment techniques to projected programs of work over the 2014–19 period. This is reasonable in light of the advice of WorleyParsons in relation to Endeavour Energy. For Endeavour Energy, Worley-Parsons noted that the application of risk based cost benefit analysis assessment techniques had the potential to reduce expenditure by between 10 and 20 %.*[151].

In fact the reference to Endeavour Energy's options to reduce expenditure by between 10% and 20% is not related to the repeal of the deterministic planning criteria and consequent used of risk based cost benefit analysis at all. Rather, it relates to benefits realised in its overall distribution works program through "*the application of risk assessment techniques to all projected programs*

[146] WorleyParson review of proposed augmentation capex in NSW DNSP regulatory proposals 2014-19 – 17 Nov 2014, section 3.4.4 and 2.4.5

[147] Ausgrid regulatory proposal 30 May 2014, p. 38

[148] WorleyParson review of proposed augmentation capex in NSW DNSP regulatory proposals 2014-19 – 17 Nov 2014, section 3.4.3, p. 12

[149] WorleyParsons endorsed this position in section 3.4.1 of their report

[150] WorleyParson review of proposed augmentation capex in NSW DNSP regulatory proposals 2014-19 – 17 Nov 2014, section 3.5

[151] AER draft decision – Attachment 6: Capital Expenditure, p. 6-35,36

of work" and "consideration of non-augmentation options"[152]. WorleyParsons did not make any similar observation in respect of Ausgrid. This demonstrates that the choice of a 15% cut to Ausgrid's overall augmentation expenditure to reflect a move from deterministic to risk based cost benefit decision making is not based on any sound analysis and cannot be relied upon as the basis of an alternative estimate of expenditure requirements.

Finally, the draft decision refers to the difference between VCR estimates from the AEMO's October 2014 review and the 2007 results. It quotes the change in the NSW overall VCR from $43.25 per kWh to $38.35 as a rationale for expecting a reduction in augmentation expenditure requirements:

> *This suggests that some projects currently included in its proposal may not be required once a cost-benefit is undertaken incorporating the new VCR values.*[153]

Ausgrid agrees that it is reasonable to use the latest estimates for VCR in any cost benefit analysis based on these values. However, to draw conclusions about changes in customer preference being evidenced by a change from the 2007 published values and the most recent state averages is to overplay the accuracy and significance of the measure.

The two surveys used different methodologies. The 2007 Victorian VCR survey used a combination of economic substitution and a direct cost approach. The 2014 AEMO survey used a combination of choice modelling and a contingent valuation approach.

The NSW estimate was derived from the Victorian survey using a re-weighting method developed by Oakley Greenwood. There were no survey elements actually conducted in NSW and the intention was to provide broadly indicative numbers. AEMO emphasised

> *These values for each non-Victorian jurisdiction are representative only. AEMO recommends the use of these values with appropriate caution and sensitivity analysis as they do not represent regional specific survey responses. These figures are indicative for each state and it should be recognised that they will not affect planning decisions in each of those states because of the nature of the planning standards.*[154]

On this basis, a comparison between the 2007 estimates and the 2014 results is not sufficiently robust to provide meaningful insight, and certainly could not be relied upon to indicate a change in NSW customer preferences.

In response to submissions from stakeholders, AEMO widened their approach to determining VCR for their 2014 report[155]. While state average numbers may be appropriate for high level state-wide transmission planning, AEMO provided much greater granularity that is useful at the distribution level. This included separate average values for residential, commercial, industrial and agriculture customers, and values for 'direct connect' customers subdivided by industry. There are also values segmented by event timing – weekday vs weekend, summer vs winter and off-peak vs peak times[156].

When considered at this granular level, VCR values for many segments (including residential customers) are substantially higher than the 2007 values. For the purpose of evaluating benefits associated with augmentation expenditure, the likelihood is, by definition, that outages will occur at peak times. Peak time VCR estimates are significantly higher than the previous average numbers.

When considering distribution investments, a suitable VCR should be calculated that is fit for the intended decision making purpose. In most cases, for Ausgrid, this results in a higher VCR rather than lower. The conclusion in the draft decision is therefore unsound. It is in fact more likely that projects would be advanced, not deferred. Fortunately, the very low demand forecasts have meant that Ausgrid has not observed this effect.

In summary, the basis for the alternative expenditure estimates for augmentation capital are much less robust than the analysis that underpinned the development of Ausgrid's original proposal. However, we recognise the validity of the need for consideration of change to demand forecasts and more explicit consideration of the opportunity for flexibility and the application of cost-benefit analysis following the removal of deterministic planning criteria.

Revised augmentation expenditure proposal

Ausgrid's revised proposal includes a forecast of $303 million ($2013/14, excluding overheads) for augmentation. This is 25% lower than our initial proposal. This expenditure forecast is based on demand forecasts that have been updated to take into account actual demand data since the submission of our initial proposal. We have also updated our forecasting model for HV distribution expenditure to take into account diversity of demand growth at distribution feeder level and the application of risk assessed cost benefit analysis. In addition a top-down adjustment for expected project and labour efficiency improvements in the later years of the period has been applied to augmentation expenditure.

The forecast augmentation expenditure is shown in Table 18 below.

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[152] WorleyParson review of proposed augmentation capex in NSW DNSP regulatory proposals 2014-19 – 17 Nov 2014, section 2.5.1

[153] AER draft decision – Attachment 6: Capital expenditure, p. 6-36

[154] AEMO, National value of customer reliability, 19 Jan 2012, p. 3

[155] AEMO, Value of customer reliability review, September 2014

[156] AEMO, Value of customer reliability review, September 2014

Table 18 – Revised augmentation capital expenditure forecast ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Area Plans	30.52	11.69	14.68	7.09	2.27	**66.26**
HV Distribution Capacity Plan	36.97	25.30	15.67	14.51	22.04	**114.50**
LV Distribution Capacity Plan	31.84	22.29	22.52	22.83	22.82	**122.29**
Total	**99.34**	**59.28**	**52.87**	**44.43**	**47.12**	**303.04**

Note: Numbers may not add due to rounding.

Revised demand forecast

The draft decision correctly identifies that the demand forecast used for our initial proposal was our 2013 forecast. We have prepared a revised forecast since then and provided the AER with an early draft of that revised forecast during the process of their review.

The new forecast incorporates the latest actual demand data (from summer 2013/14 and winter 2013). We have also further improved the methodology of our forecasting to take better account of top down econometric factors and to incorporate a revised normalisation approach (including a change to our weather correction metric).

As a result, the normalised historical demand at many zone substations has changed, leading to changes in the trend analysis used to determine the starting point for forecasts. This, combined with a lower underlying growth projection, has resulted in a reduction in forecast demand at most points on the system.

The following charts provide an overall system level view of the change to our forecast from 2013 to 2014. Figure 11 shows the revised forecast has both a lower starting point, and a period of short-term system-wide decline in demand followed by a return to positive growth in the medium term. Figure 12 shows the diversity of demand growth between Ausgrid's 177 zone substations. While the majority are now forecast to have the same or slightly lower demand in 2019 compared to 2014, 11% of zones will experience growth in summer demand over the period and 22% will experience growth in winter demand.

Figure 11 – Ausgrid summer system coincident peak demand (MW) – 2014

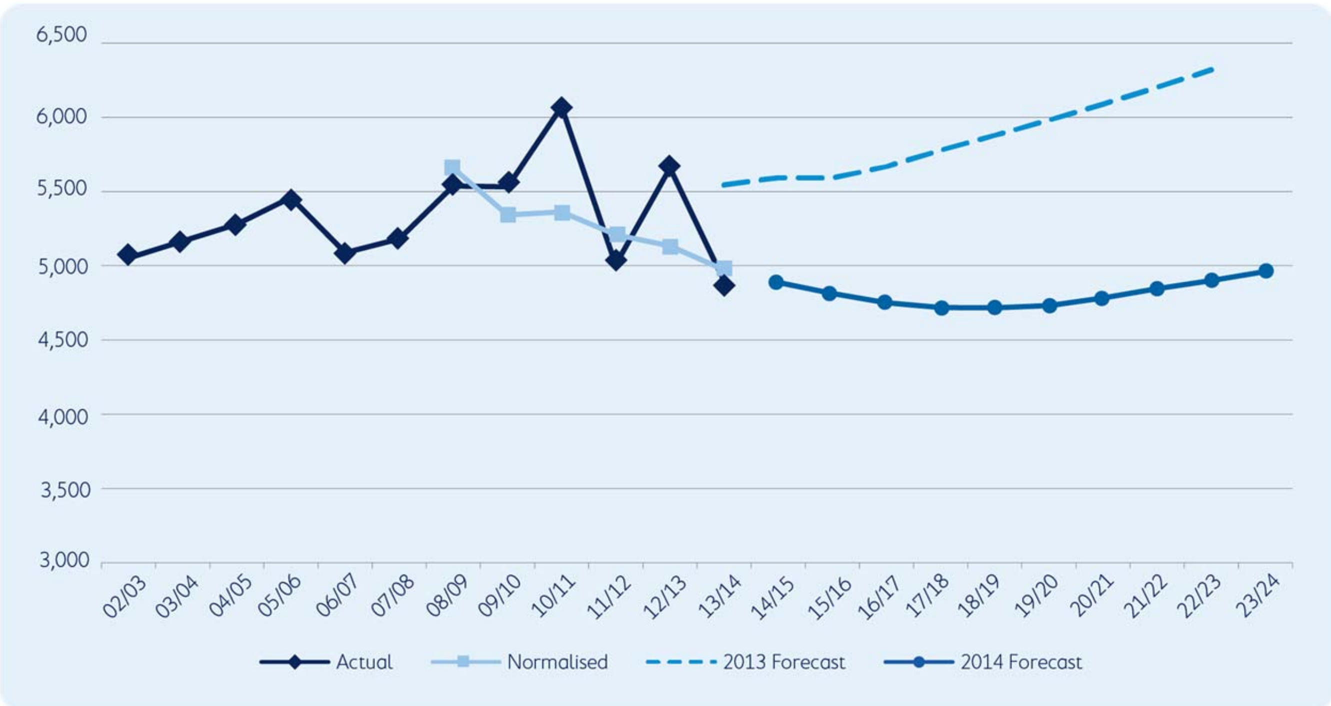
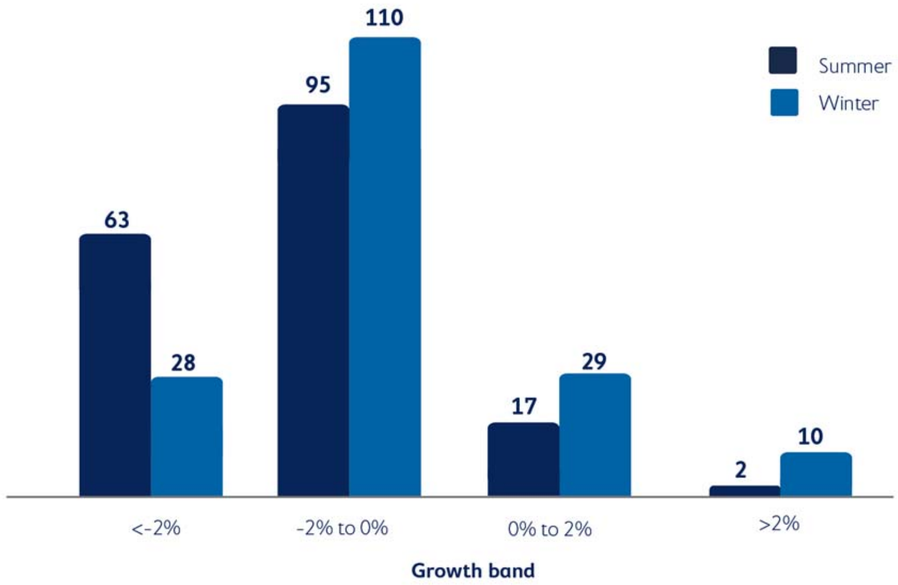


Figure 12 – Annualised zone substation summer growth rates 2014-2019



Further details about our forecast approach for the 2014 forecast, and discussion of the similarities and differences to the AEMO connection point forecast can be found in Attachment 5.01. The detailed forecast is contained in Attachment 5.02.

Area plan augmentation expenditure

The initial proposal was based on the results of the 2013 area plan review. The 2014 review takes into account changes in demand forecasts and other inputs since that time. As a result no subtransmission projects are proposed for the 2014-19 period that are driven by load growth except for projects that are currently in progress. There are two planned projects that are classified as augmentation. However in each of these cases, the shortfall in capacity arises as a result of retirement of assets in poor condition rather than load growth. The augmentation expenditure component of the area plans is shown in Table 19.

Table 19 – Area plan capital expenditure forecast ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Work in progress	29.62	8.76	2.07	0.00	0.06	**40.52**
Forecast new augmentation projects	0.30	2.45	12.12	4.95	0.29	**20.11**
Strategic property acquisition	0.60	0.48	0.49	2.13	1.92	**5.63**
Total	**30.52**	**11.69**	**14.68**	**7.09**	**2.27**	**66.26**

Note: Numbers may not add due to rounding.

The 2014 area plan review report is included as Attachment 5.03.

Distribution capacity plan

Recognising the shortcomings of our HV distribution model identified in our initial proposal and in the draft decision, we have reconfigured the model using input modifications and post model adjustments. While the model itself remains unchanged in its operation, the inputs are now pre-processed to take into account observed within zone variation in growth rates between HV feeders. This has resulted in an increase to forecast expenditure –especially in zones with low average demand growth – compared to the simple model. In addition, the outputs are now subjected to a post model adjustment to recognise the expected impact of risk based cost benefit analysis on expenditures following the removal of deterministic licence conditions. This has reduced the overall expenditure forecast. The net result is that our revised forecast expenditure is 25% lower than was forecast in our initial proposal.

The approach used to develop these adjustments, along with comparisons of results is contained in Attachment 5.04.

Modelling for LV capacity expenditure was not challenged in the draft decision. Our modelling has shown that this sector is driven primarily by new customer connections. The diversity of local growth is so pronounced at this level that there is no discernible relationship to average growth rates at zone substation level. Economic forecasts suggests a slight increase in the connections activity that is the key driver for this expenditure category. However the change is not material and we do not propose to amend our forecast for this category.

Table 20 – Distribution capacity plan capital – revised expenditure forecast ($ millions, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Work in progress	24.29	12.72	0.02	0	0	**37.03**
Forecast HV capacity	12.68	12.59	15.65	14.52	22.04	**77.46**
Forecast LV capacity	31.84	22.29	22.52	22.83	22.82	**122.29**
Total	**68.81**	**47.59**	**38.19**	**37.34**	**44.85**	**236.79**

Note: Numbers may not add due to rounding.

5.4 Connections expenditure

The draft decision

The draft decision identified Ausgrid's forecast connections expenditure as $171.1 million, excluding overheads. The draft decision considered this amount reasonably reflected the required expenditure. The draft decision also accepted Ausgrid's forecast for capital contributions of $522.29 million ($2013/14).

Ausgrid's response

Ausgrid accepts the draft decision in principle. However, Ausgrid has concerns with the way capital contributions were factored into the overall capital expenditure decision. Unlike other jurisdictions, the contestability regime in NSW means that the vast majority of capital contributions come in the form of contributed assets that are designed and delivered in a competitive market environment. These are delivered under contracts between customers and each designer and constructor. The contributed assets arising from this process are quite separate from Ausgrid's capital programs.

In the capital expenditure model[157] the item labelled 'balancing item' in the RIN data was allocated across the remaining expenditure categories[158]. Ausgrid had provided the RIN data in accordance with the explicit instruction not to include gifted assets in either augmentation or connections capital expenditure. In part, the effect of the approach in the draft decision was to allocate the value of capital contributions across the augmentation, replacement and connection expenditure categories.

Following reductions applied to the augmentation and replacement categories, the original full value of capital contributions was subtracted from the remaining 'gross capex' to arrive at a 'net capex' value for Ausgrid. This is not appropriate. It is Ausgrid's view that the capital contributions should be treated only as a revenue equivalent item and there is no basis for allocating the value of the capital contributions into Ausgrid's capital expenditure forecasts. Nor is there any justification for reducing the value of assets provided by a competitive market under the control of customers.

Our initial proposal identified our forecast expenditure for connections as $206 million (including overheads), including $25 million in area plans relating to major subtransmission connections. The RIN data provided alongside our initial proposal reflected these amounts in table 2.5.2 but the total in table 2.1 incorrectly represented this as only $165 million. The draft decision calculated the value for connections as $171 million after allocating the balancing item and correcting for other anomalies in the RIN data. In the revised RIN data provided to the AER on 10 December 2014, we isolated all these issues so that the balancing item included only the capital contributions amount, and it was not included as part of any other category. This identified that the correct value for forecast connections expenditure in the initial proposal was $193.6 million ($2013/14, excluding overheads).

As part of the 2014-19 determination, we were required to submit a revised connection policy in accordance with the connection charge principles set out in Chapter 5A of the NER and the AER's connection charge guidelines. The new policy was approved as part of the transitional determination and confirmed in the draft decision[159]. The effect of this change is to reduce the amount that Ausgrid contributes to the cost of connection new customers.

The initial proposal included recognition of the change in connection policy on 1 July 2014, and the impact this would have on the balance between capital investment by Ausgrid and contributed assets constructed by connecting customers. However, the forecast did not properly account for the implementation time frame of this change. The policy applies to all connection applications received from 1 July 2014. Because it will take some time for applications received prior to that date to be processed through to finality, there is a delay in the impact of this change on both Ausgrid's connection expenditure and the value of capital contributions. This phase-in effect has been taken into account in the revised proposal resulting in a reduced forecast for capital contributions of $477 million in the revised proposal (see below).

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[157] AER draft decision Ausgrid distribution determination - Ausgrid 2014 - Consolidated capex forecast model - November 2014.xlsx

[158] "Adjustments and unaccounted for capex", AER draft decision – Attachment 6: Capital expenditure, p. 6-13

[159] AER draft decision – Attachment 18: Connection Policy, section 18.1, p. 18-8

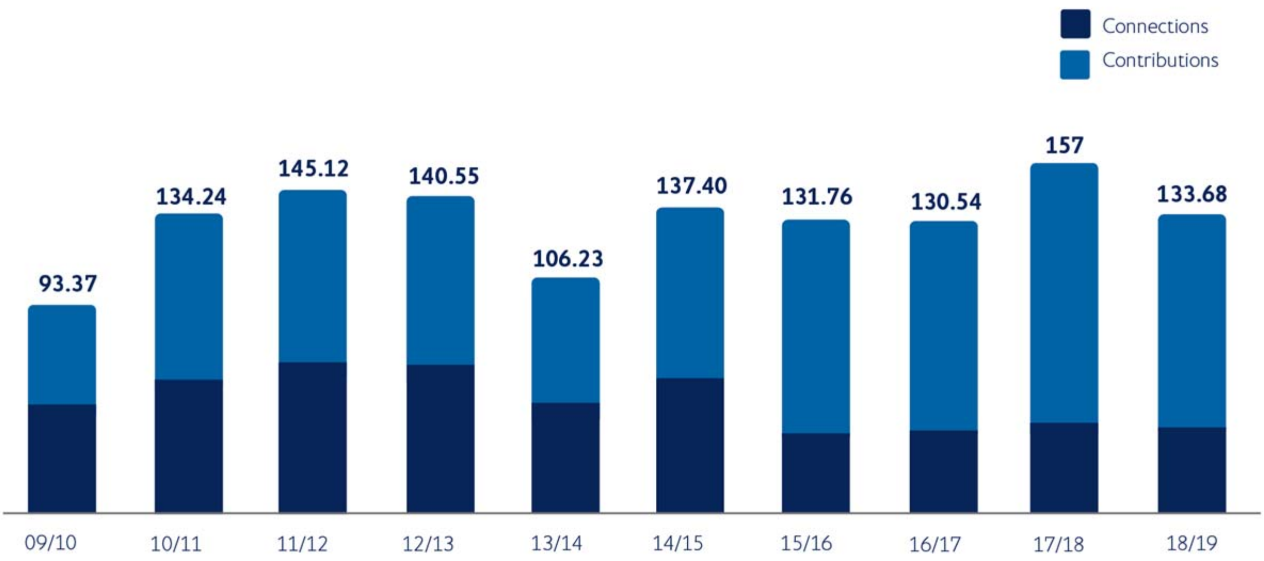
Revised connections expenditure proposal

Ausgrid's revised proposal includes a forecast of $213.1 million ($2013/14, excluding overheads) for connections expenditure incurred by Ausgrid. This reflects corrections to the value in the draft decision to account for the incorrect allocation of costs and the balancing item from the RIN, and adjustment for the phasing in of the impact of the 1 July 2014 policy change.

We have also reviewed our forecast of connection activity and there are indications of increased connections activity compared to our previous forecast. However, the differences are not material. On this basis we have elected not to adjust the basis of our forecast of connections expenditure in this revised proposal[160].

The chart below demonstrates the relationship between connections expenditure incurred by Ausgrid and the value of assets contributed by connecting customers under the contestability regime. Note the delayed change in the relativity between the two arising from the change in policy on 1 July 2014.

Figure 13 – Connections expenditure and contributed assets value – revised proposal ($ million, 2013/14)



Capital contributions

Consistent with the discussion relating to connections expenditure above, we have adjusted down the value of expected capital contributions for 2014/15 compared to the figures underpinning our initial proposal. Ausgrid's forecast of capital contributions in this revised proposal is $477.3 million ($2013/14).

Ausgrid's revised proposal for connections investment and capital contributions is shown in Table 21.

Table 21 – Connections capital – revised expenditure forecast ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Connections	60.8	36.2	36.7	40.6	38.8	**213.1**
Capital Contributions	76.6	95.6	93.9	116.4	94.9	**477.3**

Note: Numbers may not add due to rounding.

[160] See Attachment 5.16 – Updated customer numbers

5.5 Replacement expenditure

The draft decision

The draft decision identified Ausgrid's forecast replacement expenditure as $3,226 million, excluding overheads. The draft decision did not accept this forecast and instead included an amount of $1,769 million for replacement expenditure. Four issues were quoted as the basis for this significant reduction:

- historical expenditure trend analysis;
- issues identified by the EMCa review;
- analysis of network health indicators; and
- delivery challenges[161].

Later in the document, it lists the assessment techniques used as:

- benchmarking and trend analysis;
- an engineering review; and
- predictive modelling[162].

Based on a full reading of the draft decision, it is clear that the benchmarking, trend analysis and engineering review have been used primarily to paint a qualitative and generally negative picture of Ausgrid's expenditure forecast. The dominant quantitative input to the alternative estimate was the outcomes of predictive modelling (REPEX) using calibrated asset lives and forecast unit rates.

The draft decision contains a number of inaccuracies, errors and misinterpretations. For example, the high level description of the draft decision states that the alternative of estimate $1,769 million represents a 43% reduction from the proposed value of $3,226 million. A 43% reduction on $3,226 million would be $1,839 million. We note that the consolidated capex forecast model[163] supplied by the AER identifies the input reduction percentage as 45.18% not 43%.

Other errors may be typographical rather than arithmetic. For example, in dealing with "Other repex", the draft decision states "*Ausgrid forecast $138 million of repex for these assets for the 2014–19 period. ... Ausgrid's ''Buildings'' asset subcategory is the largest of these, with $111 million forecast ... Given the significant downward trend, we have not undertaken a review of this category. .... We are therefore satisfied that the total of $111 million in the "other" asset group is likely to be a prudent and efficient level of repex*"[164].

It seems clear from the text that the intention was that the category expenditure forecast of $138 million was considered prudent and efficient, but that the total was substituted in the discussion of one of the constituent items and the recording of $111 million as the value for the whole category was an error. The draft decision does not provide a table to demonstrate whether this error flowed into the overall alternative estimate. However, back-calculating the arithmetic from the statements in the "position" section[165] it seems clear that the erroneous $111 million figure was used.

While these errors of logic and arithmetic are often not material in their own right, the direction is unwaveringly negative and this suggests a generally low level of reliability of the overall assessment.

Ausgrid's response

Ausgrid rejects the outcome of the review of replacement expenditure forecast and the analysis that underpins it. In each area the tools that have been used to review our proposed expenditure have been based on incorrectly interpreted input data, have been misused, been inappropriate for the purpose, or the results have been misinterpreted.

In common with the approach to augmentation expenditure, the external review and in-house analysis by AER staff on which the draft decision relies is insufficient to constitute either a robust review of our proposal, or a robust basis for an alternative estimate.

Ausgrid's concern about the quality of the analysis underpinning replacement expenditure recommendations are reinforced by the report by independent consultants Jacobs which found:

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[161] AER draft decision – Attachment 6: Capital expenditure, p. 6-11

[162] AER draft decision – Attachment 6: Capital expenditure, p. 6-49

[163] AER draft decision – Attachment – Ausgrid 2014 - Consolidated Capex Forecast model - November 2014.xlsx

[164] AER draft decision – Attachment 6: Capital expenditure, p. 6-73, 74

[165] AER draft decision – Attachment 6: Capital expenditure, p. 6-49 identifies a total of $339 million for categories which we assume is comprised of $160 million for SCADA, and $68 million for pole top structures, leaving $111 million for other repex.

This section of the AER draft decision displays an appalling misunderstanding of the fundamental drivers of repex in any DNSP.[166]

In some cases, legitimate concerns have been identified and we have moved to address these in our revised response. In general we have achieved this through ongoing improvements to our analytical processes developed in the period since the submission of the initial proposal. In addition, the normal changes and updates to plans over the intervening period have seen changes to inputs, which have also been incorporated into our revised proposal.

In the main, however, Ausgrid stands by the basis of our initial proposal and asserts that, taking proper account of the age and condition of our assets, the proposed replacement expenditure is both efficient and prudent, and is in the long term interests of consumers.

Ausgrid's initial proposal

Replacement expenditure in Ausgrid's initial proposal consisted of elements of the area plans, the technology plan and the replacement and duty of care plan. Combined, these elements add up to a forecast replacement expenditure total of $2,707 million ($2013/14, direct costs). As we have noted, the draft decision relied on data from the RIN provided alongside our proposal, not on the information contained within the proposal itself. The definitions and rigid structure of the RIN notice made it difficult to properly represent our proposal and assumptions made in the draft decision about the interpretation of the data led to a substantial overstatement of our proposed replacement expenditure forecast. The key issues relate to the way overheads were netted out, the treatment of the balancing item and the apportioning of non-network ICT elements across network expenditure. The relative size of the replacement category of capital expenditure amplified the effect of these assumptions.

It is important to note that the component of the forecast expenditure that is termed "duty of care" comprises a range of expenditures necessitated by risk issues not related to the deterioration of existing assets over time. These programs are typically in response to environmental or safety issues that require capital expenditure on existing assets to rectify the situation. We have categorised them under replacement because they are focussed on modification or upgrading of existing assets. These investment cases, while still fundamentally a risk – cost trade-off, exhibit a different profile to condition based replacement investment. Duty of care programs comprise about 12% of the replacement investment category.

Trend analysis

The draft decision includes a chart (A-5[167]), that it claims shows historical and forecast replacement expenditure from 2001/02 to 2018/19. The data used to formulate the chart was derived from multiple sources that have used varying definitions over time. We have prepared a corrected version of the same chart with consistent data, and based on our revised proposal and overlaid it on the original chart A-5 from the draft determination.

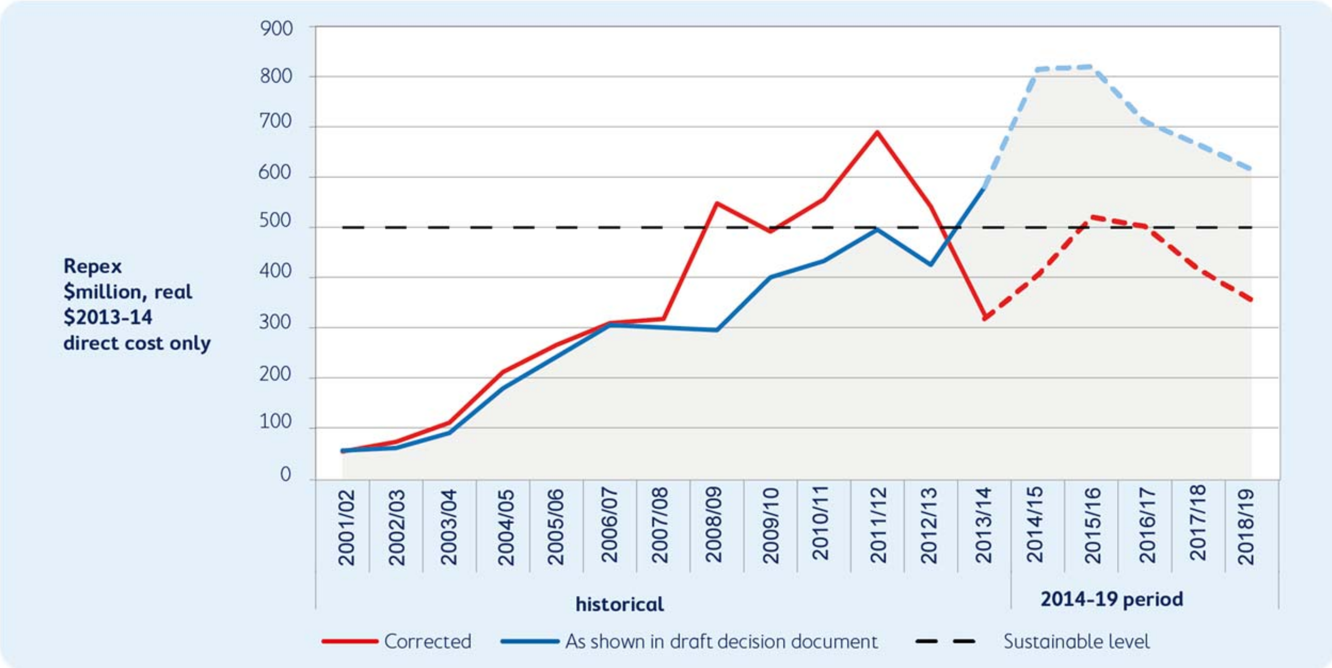
An alternative high level indicator of prudent levels of replacement expenditure might be to calculate an average expected level of expenditure required to maintain an asset base the size of Ausgrid's. The current replacement cost value of our entire asset base has been estimated at about $38 billion. If we assume an average lifetime of our assets of around 60 years – longer than most networks would expect – and further assume a steady state environment and a simple random spread of asset ages, this would imply that about one sixtieth of the asset base would require replacement each year. On a base of $38 billion, this would translate to a sustainable replacement expenditure level of $630 million per year. Efficiencies and synergies with augmentation investment needs could see this equates to perhaps $500 million per year.

Superimposing this high level view of long term sustainable replacement expenditure on the trend chart from the draft decision, and correcting the underlying data to make it consistent yields Figure 14 below.

[166] Attachment 5.08 – Jacobs - Review of AER Draft Decision - Repex, p. vii

[167] AER draft decision Attachment 6: Capital Expenditure, p. 6-51

Figure 14 – Historical and forecast replacement expenditure



However, regardless of the correctness of the underlying data, the use of historic trends to indicate the efficient level of replacement expenditure is fundamentally flawed and could be described only as 'very generally indicative' at best. This is particularly the case where the original asset base has been established in a "lumpy" fashion, for example due to the boom periods of the 1960s and 1970s, which is the case for Ausgrid. This view is supported by an independent consultant report from Jacobs:

> *Jacobs fundamentally disagrees with the AER's premise that the future requirement for sustainable long term replacement expenditure for a DNSP can be predicted by looking at recent past expenditure.*[168]

The draft decision used the data in this chart to calculate that Ausgrid's proposed replacement expenditure was "*a 41 % increase above its long term average repex and a 56 % increase in the amount incurred in the most recent regulatory control period*"[169]. Due to the errors in the data, this statement is incorrect.

Based on the corrected data, the historical average replacement expenditure over the last two regulatory periods was $425 million per year, approximately equal to our revised expenditure forecast. Furthermore, Ausgrid's revised replacement expenditure proposal is 15% below our actual expenditure in the last regulatory period.

The appropriate use of such high level indicators should be to identify where deeper analysis is required to understand the situation. In this case, an understanding of the circumstances provides an insight into the investment conditions faced by Ausgrid over the past 15 and future 5 years.

In the early 2000's Ausgrid faced investment constraints driven by the pricing decisions of the day that provided inadequate revenue to service the most prudent level of investment in the network. The connection of customers and maintenance of supply capacity during a period of considerable demand growth were the priorities and this meant little available funding for timely replacement of deteriorating assets. Ausgrid responded by developing life extension strategies and sophisticated maintenance analytics to enable reasonable performance despite this revenue shortfall, and the relatively higher level of augmentation expenditure provided some low cost replacement opportunities. In the mid to late 2000's it became clear that performance would deteriorate without further investment and the NSW government responded with the imposition of licence conditions aimed at restoring appropriate levels of network security and reliability. During the same period, Ausgrid developed its asset information and analysis systems to provide a compelling case for a substantial increase in replacement expenditure.

In 2008/09 the AER made a determination for the 2009-14 period that increased revenues to support a much larger investment program, which it judged as reasonable, prudent and efficient at the time. A rapid ramp up of investment began even before the

[168] Attachment 5.08 – Jacobs - Review of AER Draft Decision - Repex, p. I

[169] AER draft decision – Attachment 6: Capital expenditure, p. 6-51

2009 determination came into force and enabled us to restore network security to prudent levels and commence the long term task of replacing assets in poor condition. Having dealt with the worst elements of the highest consequence risk areas (mainly subtransmission elements), our proposal now focuses on a return to a long term sustainable replacement expenditure path that will serve the long term interests of our customers. Also evident is the change of focus in 2012 towards greater discipline in investment analysis after a period of rapid delivery capacity building, and the disruptive effect of major reforms commencing in 2012/13.

This is a considerably different conclusion to that reached in the draft decision. On the basis of incorrect data, the draft decision asserts that Ausgrid's proposed replacement expenditure forecast is 41% above the long term average and 56% above the recent 5-year period. The corrected figures show that this is not the case. Ausgrid's forecast replacement expenditure represents an increase on the unsustainable expenditure levels of the early 2000's, and a decrease on the 'catch up' levels of the early part of the most recent period. This represents a return to a sustainable level of ongoing replacement expenditure consistent with maintaining a safe and reliable network that will prevent a repeat of the boom-bust investment cycles of the past and the consequent inherent inefficiencies arising from having to adjust delivery capability to meet such extreme cycles.

Delivery concerns

The draft decision compared the expenditure on replacement in the last regulatory period with the amount that was determined to be prudent and efficient by the AER in the previous regulatory determination.

As mentioned above, the relative reduction in expenditure toward the end of the 2009-14 period had several causes. The challenges of scaling up rapidly had presented issues early in the period, but these were largely overcome. However the two dominant causes of the reductions in replacement spending late in the period were an increased focus on efficient expenditure, and the short term disruption effect of a major organisational restructure. Recognition of the higher than expected cost of some brownfield replacement options was part of the driver for reconsidering the balance between risk and cost, and Ausgrid responded to the inherent incentives in the regulatory framework. Several top-down driven reviews of the need and timing of replacement projects were undertaken, both within Ausgrid and under the Networks NSW framework.

It is important to recognise in this discussion that regulatory determinations set revenue levels with consideration of safety, reliability and price, they do not set expenditure levels. The presence of a relatively fixed revenue provides a strong incentive for network businesses to find more efficient means to reduce or redirect expenditure where this is consistent with maintaining a safe and reliable network. ARUP has prepared a report[170] validating the appropriateness of our workforce planning during this period, which supports this view.

Nonetheless, it is reasonable that the AER should consider the deliverability of a proposed expenditure program. At the highest level, the overall forward capital expenditure program in our initial proposal peaked at a network expenditure[171] of $841 million ($2013/14, direct only) in 2014/15 and was forecast to decline each year thereafter. This compares with a program of $1,316 million delivered in 2011/12, and a record of delivery in each of the last six years at equal or higher levels than that in the initial proposal.

The deliverability of the proposed program has been supported by an independent consultant review:

> *While Jacobs' considers their ability to deliver their 2014-19 Expenditure Proposals to be demonstrated by the delivery of larger capex programmes over the 2009-14 period it is not clear what the outcome will be of deferring such large proportions of network investment. The AER does not appear to have considered the future impacts of the deferred expenditures. It Jacobs' view there is significant potential for this to lead to unmanageable capex programmes in future, particularly in the case of Ausgrid and Essential Energy's future repex requirements.*[172]

At a more granular, but observable level, Ausgrid is currently engaged in a 'mix-and-match' voluntary redundancy program for electrical trades staff designed to enable us to employ our current apprentices. This would not be consistent with the actions of an entity that is expecting difficulty in delivering its forward program.

A more detailed delivery strategy has been developed since the submission of the initial proposal and forms part of our revised submission. A copy of this plan is included as Attachment 5.5.

Benchmarking

As discussed in section 5.1, Ausgrid has significant concerns about the benchmarking approaches used to review capital expenditure in the draft decision generally. Many of these relate to potentially misleading views of asset age and condition and other characteristics that make one distribution business different from another. More detail regarding these concerns can be found in Chapters 1 and 6 and relevant referenced attachments.

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[170] Attachment 6.02 - CEG: Labour unit cost – review of Deloitte report (CONFIDENTIAL)

[171] Replacement connections and augmentation, direct costs

[172] Attachment 1.16 - Jacobs - System Capex and Maintenance Prudency Assessment, p. 52.

In the case of the benchmarks selected for comparison of replacement expenditure, the draft decision takes several approaches:

Figure A-7 and A-8[173] purport to normalise replacement expenditure by comparison to customer density metrics. However, the expenditures are presented in absolute terms and do not, as the draft decision claims "*account for the impact of Ausgrid's network size*[174]" in any way. Comparing distribution businesses based on density measures is a legitimate approach, but only after correcting for key underlying factors like size, scope and asset age in some appropriate way. This betrays a fundamental misunderstanding about the function of normalisation that questions further the draft decisions reliance on drawing invalid conclusions from inappropriate metrics. Jacobs, in their review of elements the draft decision say:

> *these two factors are largely unrelated to the underlying drivers of repex*[175].

Figure A-9[176] is a small improvement, in that it does provide for a level of normalisation. However, as noted in the discussion of benchmarking in section 5.1, the 2008 regulatory asset base (RAB) is not the most appropriate measure of business size. This was discussed at the beginning of this section of our proposal, and supported there by independent consultants' reviews.

Further we note that the axes on the chart are incorrectly labelled. The draft decision does acknowledge a range of limitations with this sort of simple benchmark.

Key considerations in this case include:

- the differences in the scope of Ausgrid compared to almost every other DNSP, especially those in Victoria due to the inclusion of a substantial transmission component and the more significant role of higher voltage assets in the NSW distribution sector generally and Ausgrid in particular;
- the fact that Ausgrid embodies three distinct service territories – arguable the densest and highest economic value CBD, a well-established urban zone, and a rural network; and
- the substantially older asset age profile of the Ausgrid network.

Of particular relevance to replacement expenditure is the relative age of Ausgrid's asset base compared to its peers. In their report on benchmarking issues, Advisian notes:

> *The AER has erroneously relied on inconsistently reported financial data to form its view that the NNSW networks are relatively 'young'. This is influenced by widely differing standard life assumptions that are used by the DNSP's for depreciation purposes. Advisian has made an alternative assessment based on the Asset Age Profile information that has been reported by the DNSP's….Advisian is of the opinion that the age profiles of the DNSP's differ, and the "ceteris paribus" assumption implicit in the benchmark modelling does not hold. On the basis of this analysis Advisian cannot concur with the AER's assertion that "The age profiles of the NSW service providers and the comparison service providers are similar, and therefore should not lead to material differences in their Opex". Therefore Advisian concludes that the AER's assessment of the relative 'age' of the NNSW networks is fundamentally misleading when compared to reported asset age profiles contained in the RIN information provided by the businesses.*[177]

Ausgrid's asset base undeniably contains a larger proportion of assets beyond the typical replacement age – a consequence of the age of the city, its rapid development in the past, and the life extension necessitated by previous periods of constrained expenditure. While Ausgrid continues to assert that it is asset condition that should be the key determinant of the asset renewal investment program, it is undoubted that an older asset base is more likely to have a larger number of assets in poor condition.

Concerns with the AER's reliance on flawed benchmarking are a common thread in independent consultant's reports including PEG. They concluded:

> *We believe that EI's current benchmarking results provide an unsatisfactory basis for any disallowance. Even with improved methods, statistical benchmarking will not for the foreseeable future be accurate enough to legitimize the large disallowances for average and poor cost performers that the AER contemplates".*[178]

We have provided additional detail of the potential shortcomings of benchmarking used in this context in Attachment 1.08. However it remains important to recognise that the appropriate use of any benchmarking review is to focus attention on the most prospective areas for further study. The opportunity to engage more fully with the detail of our initial proposal has been overlooked in this draft decision.

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173 AER draft decision – Attachment 6: Capital expenditure, p. 6-52, 53

174 AER - draft decision – Attachment 6: Capital expenditure, p. 6-52

175 Attachment 5.08 – Jacobs - Review of AER Draft Decision - Repex, p ii

176 AER daft decision – Attachment 6: Capital expenditure, p. 6-55

177 Attachment 1.09 - Advisian - Review of AER benchmarking, January 2015, p. 4, 77.

178 Attachment 5.08 - Jacobs - Review of AER Draft Decision - Repex, p.54

Combined with the evident errors and misinterpretations, the results of this level of benchmarking do not constitute a valid basis for any conclusion regarding the proposed expenditure forecasts.

Network health indicators

The draft decision derives "weighted average remaining life" from financial data that it suggests reveals the trend in age of Ausgrid's network. There are two key weaknesses in this approach.

The first is the use of financial data to determine asset age. Figure A-10 uses derived asset life data on the basis of RAB values, capital expenditure additions and depreciation. These calculations are flawed because;

- RAB values and expenditure are not comparable since RAB values are based at a point in time and do not reflect the replacement value of the assets; and
- the calculation assumes that no assets are beyond their accounting lives so that the depreciation relates to all assets in service.

Noting that a much higher proportion of Ausgrid's assets are already beyond their accounting lives, this simplistic measure creates a false impression that the remaining lives of our assets are generally increasing.

Given that Ausgrid supplied detailed data on recorded installation dates for many asset classes it seems unnecessary to approximate using such a method. The evident step changes in asset average remaining life between 2009 and 2010 should have been a sufficient alert that this method is flawed. It is unreasonable to expect that an increase in average remaining life of six years could have been achieved in a widely distributed asset classes like high voltage underground and overhead assets in just one year. For example, to achieve a six-year increase in average remaining life of the current underground cable population, we would need to install $8 billion of cable (14 times the highest ever historical amount), and retire every cable installed before 1986 – more than half the entire population. So not only was it unnecessary to approximate asset age using this method, but the results are clearly inaccurate compared to recorded asset installation data.

The second key weakness is the use of average age data to represent the health of a network. Ausgrid identified this as a hazard in the initial proposal, using examples of three classes of assets for which we had high quality data[179]. Any consideration of asset condition that uses the simplistic metric of asset age as its base must consider the profile of asset ages, not just the average.

In this regard, Advisian found that:

> *The AER's underlying assumption that the NNSW DNSPs all have relatively 'young' networks is flawed as it is based on the calculation of a Weighted Average Remaining Life from the reported financial data. This is distorted by the substantially different 'standard life' assumptions used by DNSP's for similar assets. A comparison based on the Asset Age Profile information reveals that Ausgrid has the second highest proportion of 'old' assets (>50 yrs) in the NEM.*[180]

Correcting for these errors and misconceptions requires an approach that focuses on the proportion of assets that are at the end of their life. As demonstrated by the asset age profiles shown in the draft decision[181], many of Ausgrid's assets display a "two humped" profile. The existence of a significant group of new assets does not make it any less likely that older assets will require attention.

The age and value data used for the charts provided as Figures A-11 to A-17 in the draft decision has been incorrectly interpreted. These were derived from data provided for use in the REPEX model. Key issues include the use of incorrect replacement cost values (for this purpose) and the effects of averaging groups of assets containing widely varying components.

Ausgrid has developed a more robust top-down approach to providing visibility of network health and the way it moves in response to actual or planned investment. This involves a hypothesis similar to that used in the REPEX model that, in the absence of detailed condition information, asset age can be a useful proxy for asset health to enable top down validation of replacement expenditure at the organisational level. By using a cumulative normal distribution centred around an assumed end of life, it is relatively simple to map a metric Ausgrid calls "Weighted asset value at risk". Our approach and results for a series of relevant asset classes are explained in Attachment 5.06. This is superior to average age because it focuses the metric on those assets that are near (or beyond) their design life and gives minimal weighting to assets that are in the early phase of life.

The chart below shows how this works for an individual asset class, in this case service lines. The expected asset life is set to 45 years, with a standard deviation of 7.5 years. Note that in 2013 there were some very old assets still in service and a large

[179] Ausgrid regulatory proposal 30 May 2014 "Age and condition of network", p. 35

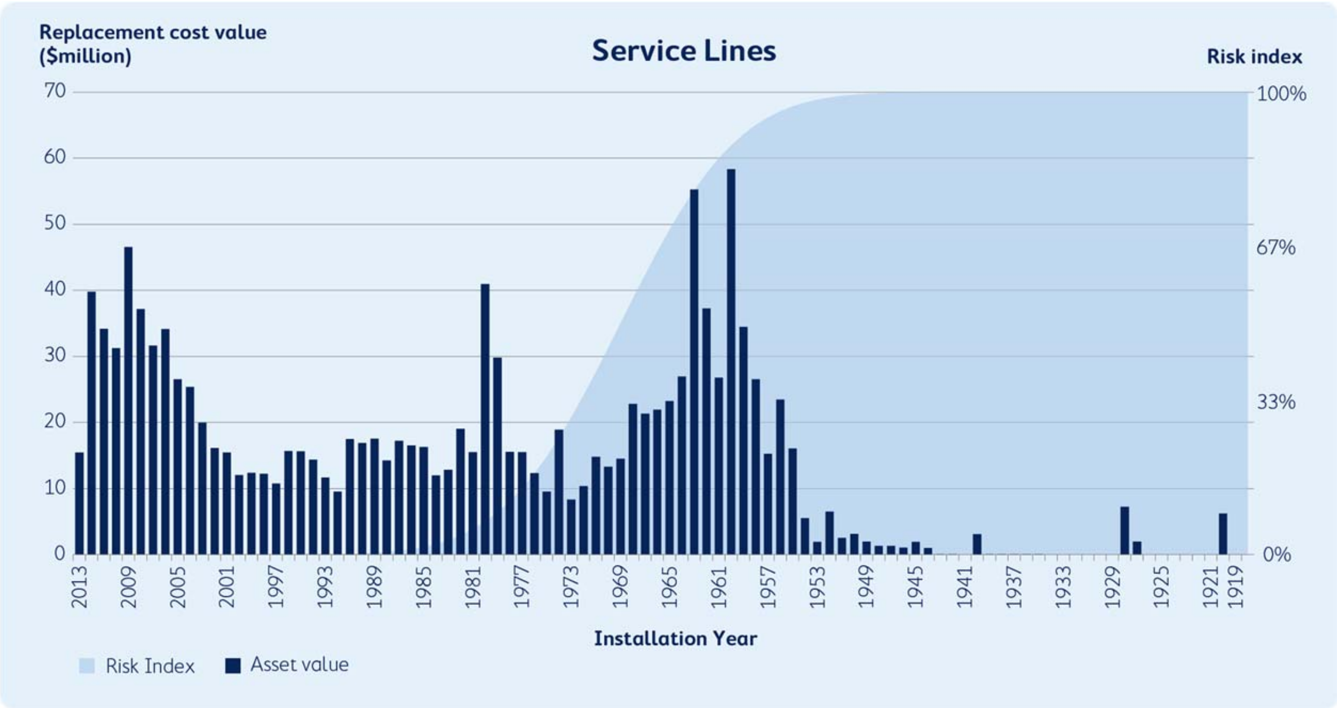
[180] Attachment 1.09 - Advisian - Review of AER benchmarking, January 2015, p. 79

[181] AER draft decision Attachment 6: Capital Expenditure, p. 6-57 to 60

proportion installed around 1960. The grey area indicates that as assets approach the nominated service life of 45 years they become more likely to be at risk, while those older than about 60 years should almost certainly be retired.

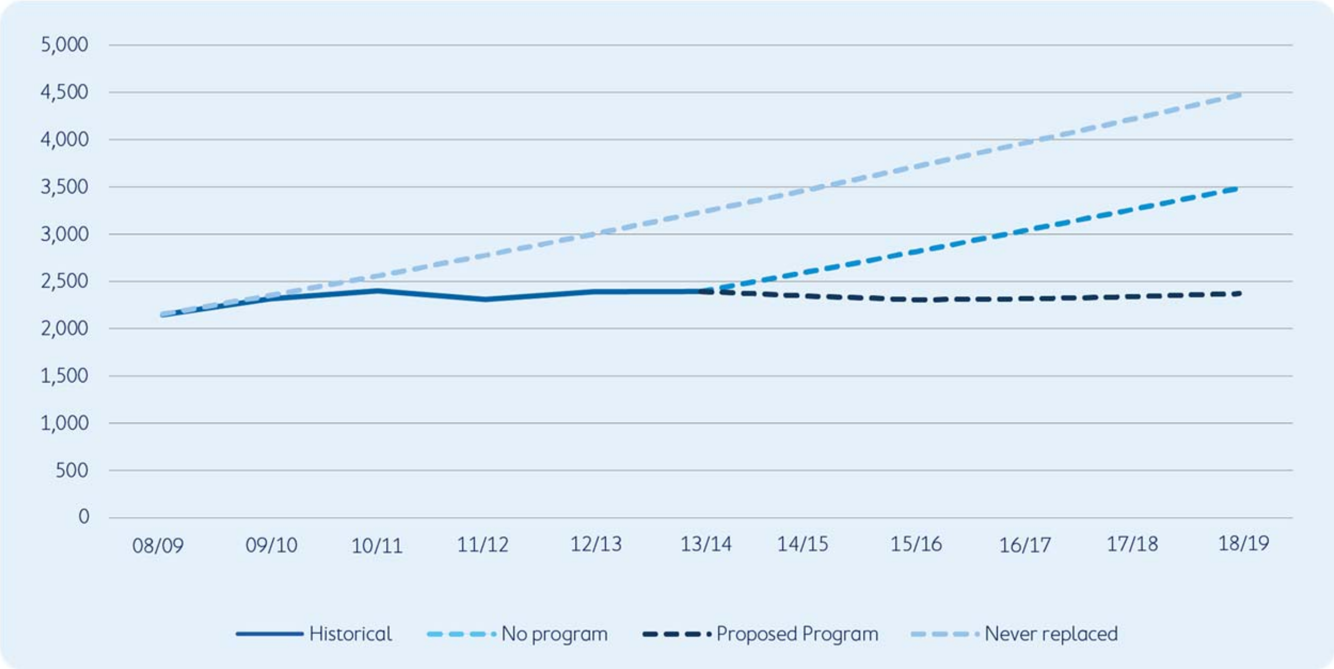
The chart compares the current replacement cost value of assets installed in each year to this "risk index". The risk index is simply a normal distribution around an expected economic life. Multiplying these together yields a "weighted asset value at risk". As can be seen, this approach is not influenced by the value of recently installed assets and focuses on the age and value of the residual older assets. This is superior to an average age or average remaining life index, which can be unduly affected by net growth in the number of assets, or be misleading due to a "double hump" asset age distribution like the one shown below, which is common across Ausgrid's asset base.

Figure 15 –Asset value at risk



Using this approach, we have mapped a high-level approximation for the movement in network-wide asset health over the past five years, a view of the change over the next five years under a scenario with no proactive investment, and the impact of the replacement program in our initial proposal. For historical reference, we have also included an indication of the hypothetical impact of no replacement expenditure since 2009. While this only includes the major assets classes, it shows a high level measure of network asset health. The conclusion is that, across the various categories, the expenditure in the last period kept the level of asset risk stable, and the trajectory provides a level of top-down assurance that the proposed program is proportionate and appropriate.

Figure 16 – Weighted asset value at risk ($ million)



The final element in asset health referred to in the draft decision is asset utilisation levels. The expectation that "*there is a positive correlation between asset condition and lower network utilisation*[182]" is not supported by any evidence or engineering review that would suggest this expectation is realistic. Electricity network assets do not exhibit wear out characteristics that relate to usage levels like automobiles might. While overloading of assets can shorten the life of the asset due to thermal degradation of components, running assets at less than rated loading does not prolong their life.

Engineering review

The draft decision identifies the EMCa review as a significant contributor to the decision: "*An engineering review carried out by EMCa found that there are systemic issues with Ausgrid's forecast that mean Ausgrid's proposal is likely to significantly overstate the amount of repex required to meet the capex objectives. In particular, Ausgrid is likely to be replacing assets many assets too early than is necessary to meet the capex objectives.*[183]"

The draft decision identifies the key findings that influenced the decision as:

- systemic issues leading to overstatement of needs and overestimation bias in cost estimates;
- management decision making issues relating to lack of consideration of alternatives, lack of cost benefit analysis and deliverability risks; and
- The use of overly conservative risk criteria.

We have prepared a detailed assessment of the EMCa report. This assessment is provided as Attachment 5.07.

The draft decision relies heavily on this report to determine that our proposal for replacement expenditure is unreliable and biased towards overestimation. While there are elements of the report that point to areas where Ausgrid could improve, our review identified several key areas of concern that undermine the validity of the resulting conclusions.

The report is described in the draft decision as an "engineering review". However, the report contains very little or no engineering analysis and is in fact primarily a review of investment decision making processes rather than the decisions themselves. The review engages very little with the substance of Ausgrid's proposal and, like the draft decision itself, relies heavily on broad overviews to draw conclusions that are expressed in generalities and qualitative judgments. Our view is that there is insufficient sound evidence in the EMCa review to support its conclusions, and that the review does not engage sufficiently with the detail of our proposal to constitute more than guidance for further examination.

[182] AER draft decision - Attachment 6: Capital Expenditure, p. 6-60

[183] AER draft decision - Attachment 6: Capital Expenditure, p. 6-49

However, instead of this being a catalyst for more direct engagement with the detail of our proposal, the report is used to effectively dismiss the entire proposal. This then forms the foundation for the substitution of sweeping changes and significantly lower expenditure estimates based on much less analytical depth or justification than that contained in the proposal.

Ausgrid accepts that its processes could always be improved, and has been working on broadening the use of cost-benefit and risk cost assessment techniques in the period since the initial proposal was prepared. This was foreshadowed in discussions with EMCa and in our initial proposal. EMCa acknowledged this as a developing area that "*shows promise*"[184] in their report. In our revised proposal we have applied a risk assessment and quantification methodology to the major replacement projects to enable us to clearly identify those projects that can be cost effectively deferred without undue risk, and those that need to proceed. We have also expanded our application of risk cost quantification to replacement and duty of care programs. However, we consider many of the claims and statements in the EMCa report to be poorly founded, based on a misunderstanding of the material provided or a misinterpretation of the discussions at the single consultation meeting held during their assessment.

On the whole, the EMCa review evidences frequent misunderstandings and misinterpretations that may be expected in a very brief and cursory examination of the very extensive documentation and information provided in our initial proposal.

For example, in claiming a likely bias toward overestimation of costs, the review alleges that there is a bias toward cost over-estimation due to the application of two layers of contingency – one at corporate level and another at project level applied at the final (gate 3) approval stage. This is a fundamental misunderstanding and is incorrect. The suggestion of a corporate level of contingency appears to come from a misreading of a policy document describing the management of contingency in a portfolio of active projects. The expenditure forecasts in the proposal comprise project estimates prior to gate 3 approval (except for in-flight projects) which do not include project contingency either. Cost estimates for in-flight projects are based on project completion cost estimates, in which contingency has typically either been drawn down or removed. Contingences are not applied twice in the project governance life cycle and there is no over-estimation bias from this factor in the proposal.

EMCa was also clearly confused about why Ausgrid does not use risk assessment approaches for some programs when it does so for others. This is primarily because some programs are purely reactive, and consist only of forecasts of equipment failures and the reactive replacement expenditure to deal with them as they arise. Programs that contain an element of proactive planned replacement are developed based on risk assessments.

Another area of confusion is with regards to what are termed "*inconsistencies and contradictions in Ausgrid's rationale*[185]", which is part of the reasoning behind the claim of poor management decision making processes. The description of these inconsistencies and contradictions contains a series of misunderstandings or misinterpretation of the information presented in the initial proposal.

- It suggests that data shows a decrease in mean age for distribution substations, poles and towers. This is incorrect. The initial proposal[186] presented a chart clearly showing that poles and towers exhibited increasing average age, and distribution substations exhibited a stable average age. Further, the accompanying discussion explains that distribution substation average age is only stable because of the growth of 3-4% in the overall number of distribution substations (all of which are obviously new), which masks the continued aging of the existing population. We identified this as one of the reasons we give little weight to analysis of average ages.
- It refers to "the need for rapid escalation of expenditure[187]". Ausgrid did not propose a significant increase in overall replacement expenditure in real terms. EMCa's report itself says "Ausgrid's proposed total repex of $3,280 million for the forthcoming period reflects a 2% increase over its total actual repex of $3,228 million in the previous period"[188]. We did propose an increase in spending in our Replacement Plan, but this plan does not cover major replacement projects contained in our Area Plans. Because the replacement expenditure in our Area Plans was forecast to be lower, the change was a shift in focus from larger to smaller assets, not a net increase, and certainly not "rapid escalation". It is possible that this misconception arose from the same errors of historical categorisation that led to the inaccuracies in the trend analysis in the draft decision that we discussed above.
- Finally it interprets our wood pole replacement expenditure forecast as "even more aggressive performance is being targeted (e.g., wood poles)". Our strategy for wood poles is a reactive inspection-based replacement using an inspection regime and safety standard that is unchanged from the previous period. Our expenditure forecast is simply a projection of the number of poles that will fail inspection and the cost of replacing them. A reading of our proposal would have revealed that the expected increase in expenditure on wood pole replacement, which occurs toward the end of the period, is due to the fact that our population of already staked poles is expected to begin reaching the end of the life extension period enabled by staking.

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[184] EMCa – Review of proposed replacement capex in Ausgrid s regulatory proposal – October 2014, p.13

[185] EMCa – Review of proposed replacement capex in Ausgrid s regulatory proposal – October 2014, p.16

[186] Ausgrid Regulatory Proposal May 2014, Figure 12 and accompanying text, p. 35

[187] EMCa – Review of proposed replacement capex in Ausgrid s regulatory proposal – October 2014, p.16

[188] EMCa – Review of proposed replacement capex in Ausgrid s regulatory proposal – October 2014, p. 6

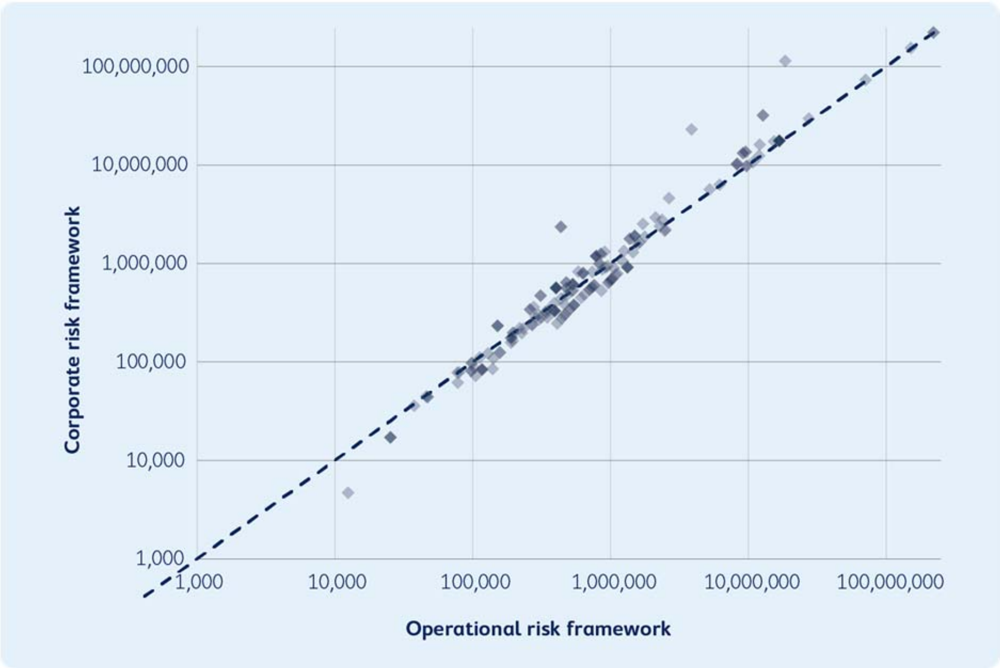
> Our current average cost of dealing with a wood pole that fails inspection reflects the fact that approximately 50% of poles are able to be staked at much lower cost than replacing the whole pole. Since a staked pole cannot be staked again, our average cost of dealing with a condemned wood pole will rise.

When these errors and misunderstandings are corrected, the logic of Ausgrid's rationale is not flawed in the way EMCa alleged.

The concerns relating to delivery risk have already been discussed above. We have provided information as part of our revised proposal that should enable this risk to be discounted as a genuine concern.

The final key finding relates to the use of "overly conservative risk criteria"[189].This criticism seems to arise mainly from the use of an operational risk framework to document replacement program risk assessments that differs from the corporate risk framework. The use of operational risk frameworks is not unusual or unreasonable. The key criticism seems to stem from the way in which likelihood and consequence inputs translate into the need for action. We have noted that we have been progressively moving to use quantitative risk cost assessments to enable us to compare dissimilar programs and provide a more accurate view of relative risks and benefits of programs. We have undertaken a risk cost mapping exercise for each of our proactive replacement and duty of care programs and compared outcomes using the corporate risk framework and the operational framework. The chart below maps the outcomes against one another.

Figure 17 – Risk consequence assessment comparison - proactive replacement and duty of care programs (risk cost in $)



While we accept that our use of this methodology for assessing risk and the benefits of risk reduction is still in development, it is clear that quantified risk under either of the risk frameworks produces substantially similar values. Furthermore, especially in the areas of higher consequence, the quantified risk under the corporate framework is higher, implying that the operational risk matrix is in fact less conservative than the corporate framework.

An additional benefit from this work has been to enable a greater awareness of comparative benefits across programs and the key drivers of risk within programs. This has facilitated a more focussed review of our replacement and duty of care needs in the revised proposal.

Predictive modelling

As noted above, the draft decision placed great weight on the outcomes of the predictive modelling in arriving at the alternative estimate for replacement expenditure. The issues with the REPEX model as applied to Ausgrid's initial proposal are in two categories.

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[189] EMCa – Review of proposed replacement capex in Ausgrid s regulatory proposal – October 2014, p. 15

The first relates to the underlying assumptions and methodologies embodied in the REPEX model and approach. At a simple, high level, predictive modelling of this type can be a useful tool for the validation of detailed replacement planning. However, it has difficulty in dealing with any class of expenditure that is not fundamentally related to asset age, with non-homogenous asset categories, and with large projects that commonly span multiple years. The REPEX model is not an appropriate high level modelling tool for all the expenditure categories in Ausgrid's proposal.

The second issue relates to the appropriateness of the data used to undertake the modelling. With only very limited exposure to the modelling approach, Ausgrid was not in a place to ensure that the data that was used as inputs to the modelling was fit for purpose. Further, the restrictive definitions required by the RIN requests and the regular changes to those definitions and data requests meant that the data used in several cases was inappropriate for the predictive modelling undertaken. For example, many asset categories which Ausgrid included in its initial proposal for replacement were not included in the RIN.

Our initial proposal included a report titled "Report – REPEX model review" authored by Networks NSW (appendix C to Attachment 5.33) that identified a series of concerns with the application of the REPEX model. In that report we identified a range of deficiencies and limitations of the model. These included that it should not be used to reject, or substitute proposed forecasts, and that it should be disregarded for certain sub-categories. The report identified a set of principles for identifying those asset groupings where it would be an appropriate top-down validation model.[190]

We commissioned Jacobs to review the application of the REPEX model following our receipt of the draft decision. In their review, Jacobs identified similar issues with the fundamental constructs of the model and said:

> *Jacobs fundamentally disagrees with the AER's premise that the future requirement for sustainable long term replacement expenditure for a DNSP can be predicted by looking at recent past expenditure.*[191]

The issue of relevant application of the REPEX model was partially recognised in the draft decision, as approximately 20% of the replacement program was excluded from the model and dealt with explicitly. We would contend that additional programs and asset categories should also have been dealt with outside the Repex model.

The application of the REPEX model produced a series of four key outputs. The first was based on Ausgrid's historical unit costs and average asset lifetimes and standard deviations based on observed replacement ages. This produced the counter-intuitive outcome that Ausgrid's replacement expenditure should be more than double that proposed on our initial proposal, with a massive expenditure required in year one. The reason for this was the basis of the asset life information we were asked to provide. Restricting the asset life data to the observed age at retirement of only those assets that had already been replaced (not necessarily due to failure or condition) created a strong bias toward lifetimes significantly younger than the expected lifetimes. This is because all the assets that are still in service – in Ausgrid's case including many of high age – are excluded from the sample. If a group of assets that were predominantly installed at a similar time (as was the case for many assets in the boom times of the 1960s and 70s), and approximately half had been retired either due to failure, damage or other reasons, then the average produced would be the average age of those that were retired early. If the model assumes this to be the required average replacement age, then most of the surviving assets would be overdue for retirement. This version of the model may have produced results that were more useful if the input life data had been more appropriately specified.

The second model version was based on observed future unit costs derived by dividing the number of units proposed to be replaced by the forecast expenditure. The number requiring replacement was still based on the incorrect life expectation data. This version also produced an expenditure forecast that was higher than our initial proposal. Part of the issue here was the disconnection between asset counts and unit costs. In many categories disparate units were summed without regard to their relative cost. For example, with underground cables there was a combination of LV pillars (measured in units) and UG cables (measured in km). While an average unit cost can work if the relative mix of quantities remains the same, it is unlikely that accurate results could result as soon as these became mismatched.

The third model used calibrated asset lives. This version assumes the past replacement volumes and expenditures are the best indicator of future efficient needs and back-solves an asset life that fits that construct. This implicit assumption is one of the key weaknesses of the model, particularly for asset classes that do not have a steady and sustainable replacement history. Jacobs identified this key concern in their report:

> *Above all other issues and factors in our review, we find that the underlying assumptions and methodology used to produce the AER "calibrated forecast" is fundamentally flawed in its logic, and for most asset categories will produce a biased forecast*

[190] Ausgrid regulatory proposal May 2014 Attachment 5.33, Appendix C "NNSW, Report – REPEX model review", p. 14

[191] Attachment 5.08 - Jacobs - Review of AER Draft Decision - Repex, p. I

which understates the real levels of Repex that will be required by Australian DNSP's to sustainably maintain asset integrity and system performance in the long term).[192]

As an example, the calibration process identifies an expected life of 134 years for fuses less than 11kV, with a standard deviation of 11.6 years[193]. This would mean that the only fuses that should be replaced in the coming period would have had to have been installed on the system the year before Edison first demonstrated the amazing new electric light in the Sydney Town Hall (which was in 1882). This is clearly an outlier, but evidences a lack of reasonableness testing for the calibrated lives, and the inappropriateness of this model for some asset classes. When combined with the forecast unit costs as above, the model produced an outcome 45% below the forecast from our initial proposal.

Interestingly, the combination of calibrated lives and historical unit costs produce an outcome that was not materially different from our forecast, but this outcome appears only in one table and is largely ignored in the text of the draft decision.

The final key model used the same calibrated lives, but benchmarked unit costs across DNSPs from around the country. This model produced an outcome about 5% lower than the model using "forecast unit costs".

Further commentary on the REPEX model and its application is contained in the review by Jacobs (Attachment 5.08).

Based on the subsequent analysis and choice of preferred substitute expenditure forecasts, we have deduced that the draft decision gave most weight to the "calibrated life – forecast unit cost" version of the model.

For the reasons identified above, Ausgrid rejects the use of the REPEX model as an effective or appropriate top-down assessment tool for all the classes of replacement and duty of care expenditure to which it has been applied. However we accept that where the conditions and data are appropriate it can provide a useful insight into the appropriateness of an expenditure forecast.

In summary, we suggest that predictive modelling of the type embodied in the REPEX model is appropriate for validating expenditure in categories of replacement expenditure that are characterised by large numbers of individual replacements, involve project durations shorter than 12 months and have sufficient data to be statistically valid. For replacement works that do not meet these criteria we propose that the evaluation be based on the detailed program, or project business case. We have identified those categories in our revised proposal and focussed on ensuring that the business cases for these elements take into account the concerns expressed in the engineering review and the draft decision.

The general asset categories for which we would not use the REPEX model would include:

- underground cables;
- 11kV switchgear in zone substations;
- duty of care programs; and
- replacement programs for non-core assets, including the asset classes that were excluded in the draft decision.

Assessing the excluded categories involves review of the relevant program business cases and the major projects contained in the area plans. Many of these programs and projects involve the consideration of high impact, low probability risks, which need to be considered individually.

This is the approach we have taken in our revised proposal. We re-present the business cases for the excluded asset categories, with improvements and changes where appropriate, and have undertaken top-down modelling using REPEX based on calibrated lives and forecast unit costs to validate the proposal for the remainder.

Asset groups not included in the model

The draft decision identifies three categories of replacement expenditure that it considered not suitable for inclusion in the predictive modelling. These were

- SCADA, network control and protection;
- pole top structures; and
- other repex.

[192] Attachment 5.08 - Jacobs - Review of AER Draft Decision - Repex, p. I

[193] AER Draft decision - Ausgrid distribution determination - Ausgrid 2014 - Repex model (calibrated - forecast) - November 2.xlsm, Asset Data, Cell H122

The draft decision suggested that the level of justification for the SCADA, network control and protection category was insufficient to justify the forecast of $252 million, and instead made an alternative expenditure forecast of $160 million based on historical averages. The EMCa review on which this decision appears to be based reviewed only a portion of the expenditure attributed to this category. EMCa considered proposed expenditure in two programs with a combined total expenditure forecast of $95 million (including overheads). The other elements that were mapped to this category in the RIN were elements of Area Plan projects. No review or consideration has been given in the EMCa review or the draft decision regarding these elements.

In regard to the elements specifically reviewed by EMCa, we accept that more information could have been provided and we have revised the forecast expenditure for this category and the underpinning business cases in our revised proposal. However, these elements represent a forecast expenditure of only $95 million of the $252 million identified in the draft decision.

The remainder of the expenditure in this category is allocated from major projects contained within the Area Plans. There appears to have been no attempt by either EMCa or the AER to include any review of these plans in formulating the draft decision.

The draft decision found that the forecast replacement expenditure on pole top structures of $68 million was likely to be reasonable.

The draft decision also states "*we are therefore satisfied that the total of $111 million in the "other" asset group is likely to be a prudent and efficient level of repex*[194]". However as noted at the beginning of section 5.5, the total forecast was $138 million. We have assumed that the transcription of the $111 million figure from the sub-category of "buildings" to the total category was an error and will be proposing a revised expenditure forecast based on the same underlying business cases.

Revised replacement expenditure proposal

Ausgrid's revised proposal includes a forecast of $2,197 million ($2013/14, excluding overheads) for replacement, including duty of care. This is 15% lower than the amount forecast in our initial proposal. This expenditure forecast is based on a full revision of our replacement plans for each program and project, and adjustments for expected improvements in project and labour efficiency. In the period since the initial submission we have further developed our risk assessed cost benefit methodologies, and reviewed and tightened the targeting of our programs. This was foreshadowed in our proposal and in discussions with EMCa. For our proposed major subtransmission cable and zone substation switchboard projects, we have developed a quantitative risk evaluation methodology. We have applied it to the significant Area Plan replacement projects to support our decision making regarding the optimal timing for these major replacements. In several cases we were able to recommend a deferral based on this analysis.

The resulting program has been subjected to a further round of top down review in preparation for presentation of the 10 year forward capital program to the Ausgrid Board. This included re-application of the AER's REPEX model, our weighted average value at risk modelling, and the customary senior management challenge processes that operate alongside the CASH prioritisation processes. As a result of these parallel processes, the forecast need for replacement expenditure has been reduced. We believe that the revised proposal deals with the valid criticisms and questions raised in the draft decision and represents a reasonable estimate of:

(1) the efficient costs of achieving the capital expenditure objectives;

(2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

In this revised proposal, we have presented our plan in categories that reflect the approach taken in the draft decision. These are:

- ***Modelled Programs***. These consist of all those programs and projects that meet the criteria for application of a modelled approach to top-down validation based on the simple proxy of age to represent likely condition, comprising multiple small projects that are relatively homogenous, and where there is a reasonable historical record.
- ***Underground cable replacement***. These programs and projects are by nature not amenable to predictive modelling based on unit costs and end-of-life statistics based on historical observation. We have proposed each of these be considered on their merits and have reviewed the risk assessments and cost benefit analyses that demonstrate the appropriateness of the timing of these investments. In the cases where detailed review and cost benefit analysis did not support continuation at this time, the projects have been removed from our revised expenditure proposal or programs have been re-sized.
- ***Zone substation switchgear***. Where these involve longer duration major projects that are not amenable to predictive modelling we have presented them as individual projects and business cases. In general these projects are replacements of entire switchboards, not individual circuit breakers and have quite different cost structures and drivers to the like-for-like

[194] AER draft decision – Attachment 6: Capital expenditure, p. 6-74

programs. In common with the large underground cable projects we have prepared detailed risk quantification assessments and cost benefit analyses and deferred those projects where the resulting business case was not compelling.

- ***Duty of care and uncategorised asset replacement programs***. The components of this category are formed from four previous sub-categories from the RIN: 66-132kV overhead; distribution substation – other and zone; subtransmission substations – other; and the existing non-categorised elements. This group comprises a range of programs that do not fit the REPEX categorisations for various reasons, and are not amenable to modelling using the REPEX approach. The components of this category include the following.
  - Duty of care program. These programs are focussed on managing risks relating to existing assets that do not primarily arise due to deterioration of condition related to time. This typically includes environmental, physical and electrical safety, and legal compliance issues.
  - Other replacement programs. These are programs or allocations from major projects for replacement of non-core assets – assets that are part of the system, but are not measurable in terms of the major asset units. Examples include earthing systems in substations, buildings, support structures and minor miscellaneous items. This includes the items included as "other repex" in the draft decision. These are not suitable for inclusion in REPEX modelling because of the highly non-homogenous characteristics and the difficulty in establishing an effective unit of measure.
  - Overhead 66-132kV. This category comprises replacement of overhead earth wires associated with overhead subtransmission feeders, refurbishment of access tracks and dealing with safety and regulatory requirements associated with water crossings. There is no element of the program for replacement of the overhead conductors themselves. REPEX modelling is not appropriate for this group of programs.
  - SCADA, network control and protection. This category was excluded from REPEX modelling in the draft decision. We have reviewed the program elements and business cases for this category and presented a revised forecast.
  - Pole top structures. This category was also excluded from REPEX based on the absence of historical data. We have not modified the definition for this category.

The revised forecast for replacement expenditure is shown by category in the table below.

Table 22 – Replacement capital - revised expenditure forecast ($ million, 2013/14, excluding overheads)

Plan	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Modelled programs	170.4	194.2	200.5	191.6	157.7	**914.4**
Underground cables	119.8	125.7	113.6	66.9	85.9	**511.9**
Zone substation11kV switchgear	25.1	39.1	36.7	27.6	15.2	**143.5**
Duty of care and uncategorised replacement	89.1	161.4	150.5	130.0	96.5	**627.5**
Duty of care*	14.4	43.2	41.5	38.2	38.6	**175.9**
Other replacement	41.7	62.4	52.9	50.6	26.1	**233.8**
132kV overhead mains	1.0	1.7	4.6	4.7	5.2	**17.2**
SCADA, network control and protection	30.3	47.0	44.8	28.9	20.2	**171.1**
Pole top structures	1.7	7.1	6.7	7.6	6.4	**29.5**
Total	**404.4**	**520.3**	**501.3**	**416.1**	**355.2**	**2,197.3**

Note: Numbers may not add due to rounding.
* Note some duty of care are in the 'Modelled programs' category.

Modelled programs

We have undertaken a review covering each program included in our replacement and duty of care plan. This review was informed by the risk quantification work we described in this chapter. We also incorporated any new risk or failure information and undertook a more granular examination of the asset categories to identify higher and lower risk sub-categories. A summary of this review and the outcomes that underpins the revised proposal is contained in our 2014 replacement plan review (Attachment 5.09).

Our revised proposal for the programs that we have classified as suitable for modelling under REPEX totals $914.4 million ($2013/14, excluding overheads).

We have re-run the REPEX model for these categories alone, including splitting the <11kV circuit breaker category into low voltage circuit breakers, 11kV circuit breakers in distributions substations, vacuum circuit breaker upgrades to existing oil circuit breakers and replacement of 11kV circuit breakers and switchboards in zone substations. The first three of these have been modelled within

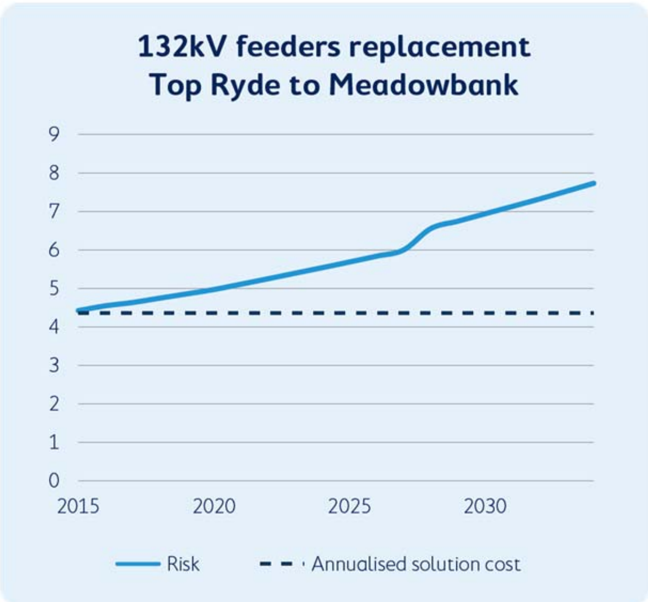
REPEX. The REPEX modelling using the calibrated asset lives and forecast unit costs results in a forecast expenditure requirement of $954.7 million. Using average benchmark unit costs and the same data resulted in a forecast of $869.1 million. Given the range of these results is from 4.4% above our forecast to 5.0% below, our view is that the comparison between program build up and modelled outcomes validates our revised proposal for this category of replacement expenditure. More detail of the reasoning behind the selection of programs suitable for REPEX modelling and the model results can be found in Attachment 5.10.

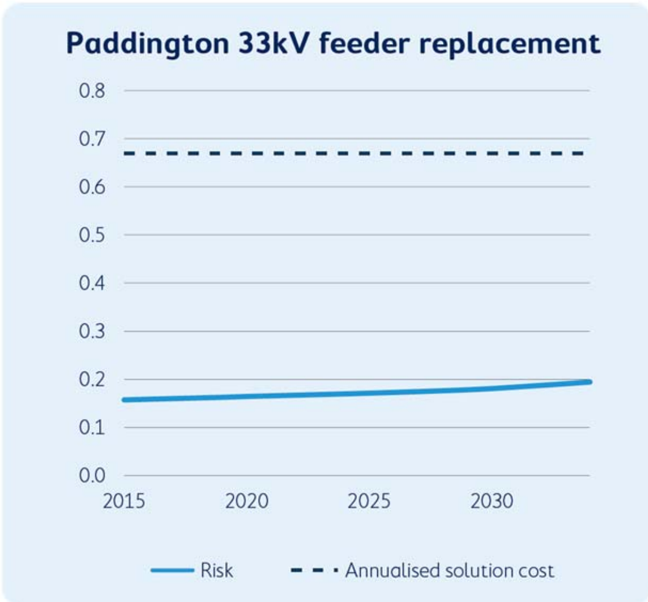
Underground cables

The majority of expenditure for underground cables is contained within the major subtransmission cable replacement projects in the Area Plans. As described in our initial proposal, these assets are the subject of a Strategic Asset Prioritisation report that identifies the issues, risks and high-level strategy and priority for retirement of obsolete technologies. Investment decisions are made within the Area Plan framework. The plans detail the alternatives considered and the reasoning behind the choice of solution. Because underground cable projects typically span several years, the units completed (km) and costs incurred by year do not correlate. Underground cable projects also exhibit a wide range of cost structures due to the location and method of installation, ranging from simple unmade ground excavation to submarine cables and tunnelling through bedrock. The disparity in unit costs and non-homogenous composition of this category makes it unsuitable for modelling using high level tools like REPEX. In addition, the potential for significant environmental impacts has meant we have agreements in place with environmental regulators to minimise oil leaks from underground oil-filled cables and ultimately remove them from service. This means a simple age based analysis like REPEX is unlikely to recognise the risks correctly.

We have completed detailed risk quantification analysis for twelve major underground cable projects totalling $218 million. An example of the outcome of the analysis is included in the figure below showing the projected quantified risk and annualised project expenditure. At the point where the risk cost exceeds the annualised cost of removing the risk, there is a positive benefit–cost ratio, and this indicated the optimal timing for replacement. These charts suggest that the Top Ryde to Meadowbank project should proceed and the Paddington project could be deferred – assuming all other considerations are accounted for. A detailed report on the risk quantification covering both underground cables and zone substation switchgear is contained in Attachment 5.11. These analyses have enabled a more complete picture of risk and consequence base on individual modelling, and have been a significant input to our revised replacement timing for some major replacement projects. We believe this represents a significant improvement in the cost benefit analysis that supports the case for the projects in the revised Area Plans. This category also includes a number of in-flight projects, and $168 million of the forecast expenditure is for completion of these projects. The outcomes have been incorporated into the 2014 Area Plan Review (Attachment 5.03).

Figure 18 – Risk-cost comparisons for subtransmission feeder replacement projects ($ million)





In addition to major subtransmission projects, there is a program for the management of underground low voltage cable involving particular inherent technology issues associated with CONSAC and HDPE cables, which have been recognised across the country as a cable technology with particular problems. As part of the 2014 Replacement Plan review, the targeting and timing of these programs have also been refined.

Our revised proposal for the underground cables category is $512 million ($2013/14, excluding overheads). This includes $391 million contained in the area plans (including $168 million for completion of in-flight projects) and $120 million in the replacement and duty of care plan.

Zone substation switchgear

The replacement of circuit breakers and switchboards in zone substations is our second major strategic replacement program. These are the subject of a separate strategic asset prioritisation report, which was presented in our initial proposal. In common with the underground subtransmission cables, these projects are large and complex, and extend over multiple years. The involvement of entire switchboards and busbar systems makes them fundamentally different to like-for-like circuit breaker replacement programs. These projects are all part of our area plans, which described in detail the range of alternatives considered, including retirement without replacement where nearby spare capacity can be utilised, and optimised projects that solve multiple problems with a single project.

As noted above, the like-for-like replacement of 11kV and low voltage circuit breakers is dealt with in the "modelled programs" segment.

The risk quantification analysis has been particularly useful in this category. We analysed twenty five zone substation switchgear replacement projects totalling $322 million. We also considered four projects where switchgear and underground feeder issues were being addressed by a single project to understand the combined cost benefit trade-off. The analysis is provided as Attachment 5.11, and the results are captured in our 2014 area plan review (Attachment 5.03).

Our revised proposal for the zone substation switchgear category is $144 million ($2013/14, excluding overheads). This includes only the allocation of the projects related to the 11kV switchboards and switchgear. The remainder of the components of the projects remain allocated into the appropriate categories within the modelled programs and other replacement categories. This component is derived from area plan projects totalling $538 million, which includes $215 million to complete in-flight projects.

Duty of care and uncategorised asset replacement programs

The draft decision placed a category we submitted as "distribution substations – other" into the Transformers grouping and our "Subtransmission and zone substation – other" category into the Switchgear grouping. In our RIN data we identified these two categories separately because they comprised a highly non-homogenous grouping of duty of care programs and replacement programs for non-core elements associated with various substations. We have included the programs classified under high voltage overhead conductors here for similar reasons. The components are explained below

- ***Duty of care program***. This comprises a range of programs that formed a major part of the RIN categories of 'distribution substations – other' and 'zone and subtransmission substations – other'. It includes a range of programs, including those dealing with asbestos management and removal, with physical (WHS) and electrical safety issues – especially in obsolete design substations and with environmental hazards. Our revised proposal for these programs totals $176 million. The original program descriptions are contained in the ACAPS documents we included with our initial submission, and the plans have been revised in our 2014 replacement plan review (Attachment 5.09).

- ***Other replacement programs.*** The largest component of this category ($167 million) is the allocation from the area plan projects (including the 11kV switchboard replacement projects) for items that are not switchgear, transformers or cables. This includes $130 million for buildings and structures, with the remainder for earthing systems and miscellaneous minor components. These expenditures form part of the projects that were reviewed in the area plan review (Attachment 5.03). In addition, there is $67 million for replacement programs dealing with similar types of equipment as part of program activity. The detail of the review of these elements is contained in the 2014 replacement plan review (Attachment 5.09). The total expenditure forecast in this category is $234 million.

- ***Overhead conductors 66-132kV***. This category comprises four programs relating to high voltage overhead conductors, but not actually involving replacement of those conductors. The key elements of this program have been reviewed in the 2014 replacement plan review. Our revised proposal for these programs totals $17.2 million.

  - ***SCADA, network control and protection systems***. We have revised this program and adjusted our assessment of these programs to provide a more appropriate expenditure profile for the revised proposal (see Attachment 5.09 for detail). Our revised proposal for these programs totals $171 million, comprised of $42 million in the replacement plan (down from $95 million) and $129 million that is allocated from Area Plan projects supporting other categories of replacement.

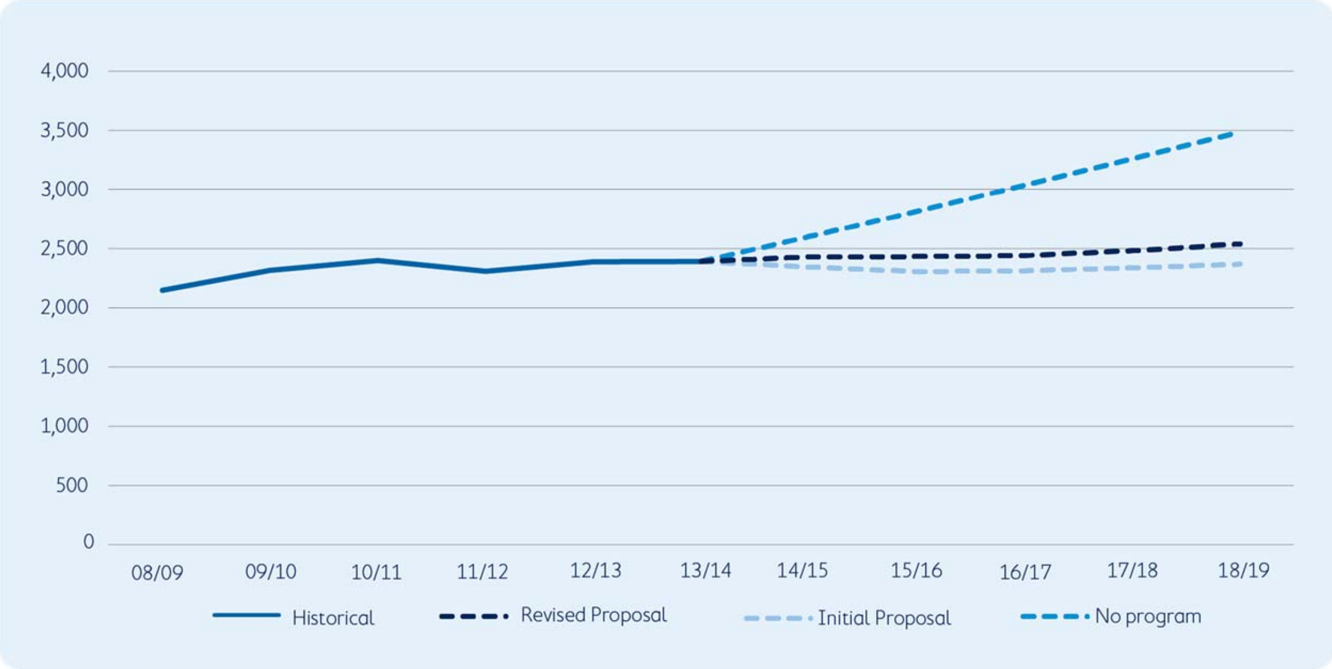
- ***Pole top structures***. This category uses the same definition as used in the draft decision and includes the same range of programs, mainly related to replacement of obsolete or dangerously deteriorated overhead air break switches. Following our 2014 review the revised proposal for these programs totals $29.5 million.

In total, our revised proposal for this category is $628 million. Documentation of the considerations and results of the all the program reviews are contained in Attachment 5.09, while the elements derived from area plan projects are included in the 2014 area plan review (Attachment 5.03).

Top-down review

Ausgrid's revised proposal includes a forecast of $2,197 million ($2013/14, excluding overheads) for replacement, including duty of care. We have modelled this program using our weighted average value at risk approach, the results of which are shown below. The analysis provides confidence that the revised proposal represents a continuation of previous levels of asset risk in older major assets and is only a small increase in risk compared to the initial proposal and is comparable with the longer term trends.

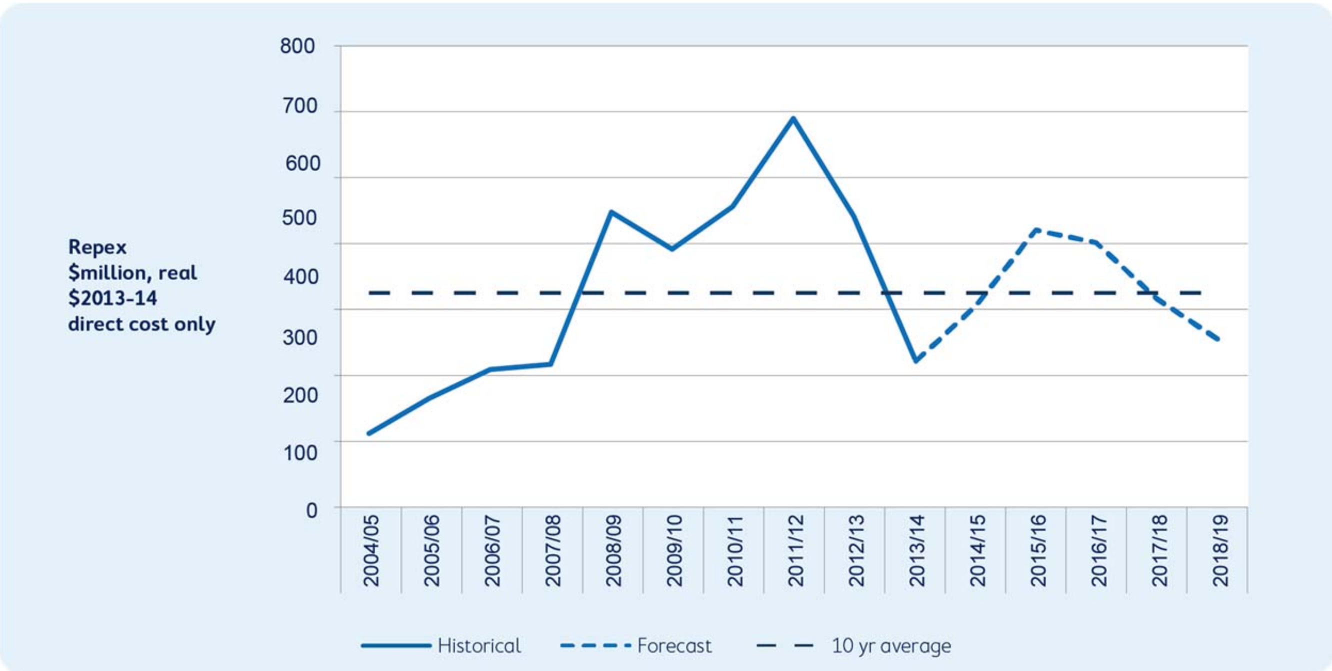
Figure 19 – Weighted Asset Value at Risk – Revised Proposal ($ million, 2013/14)



REPEX modelling has provided assurance that the smaller unit replacement programs are reasonable, and the explicit quantification of risk for major items provides a great deal of confidence that our major asset replacement strategies are also robust, efficient and prudent.

The trend analysis we presented in Figure 14 was based on our revised replacement expenditure forecast. The chart is reproduced below showing the past ten years (two regulatory periods) and the five-year forecast from our revised proposal.

Figure 20 – Historical and forecast replacement expenditure – revised proposal



The revised proposal for replacement expenditure represents a 15% reduction from the expenditure of the last period, and an average annual expenditure very similar to the ten year historical average trend. Given Ausgrid's circumstances and history, and noting that a high level assessment of expected replacement expenditure would see us spending around $500m per year, this represents a return to a long-term sustainable level of expenditure on asset management.

The results of our top-down cross checks give us confidence that our revised proposal for replacement and duty of care capital expenditure is a reasonable estimate of the expenditure requirements of a prudent and efficient operator.

5.6 Reliability investment

The draft decision

The draft decision identifies Ausgrid's forecast expenditure of $28.3 million ($2013/14, including overheads) to meet its network reliability performance obligations. The draft decision recognised Ausgrid's forecasting methodology as sound. However, it did not accept the forecast on the basis that it was not clearly identified as being part of replacement or augmentation expenditure, and the potential for funding offsets through the STPIS mechanism was not clearly considered. The draft decision requested further information to be provided in the revised proposal.

Ausgrid's response

In the RIN data, the reliability investment plan was included in the augmentation category despite the investment to meet the reliability licence conditions typically not being of the nature of either augmentation or replacement. Ausgrid supports the approach in the draft decision of considering this investment component explicitly, rather than as part of either augmentation or replacement expenditure, and we have presented it separately in the revised proposal.

Our revised proposal considers the potential to offset part of the expenditure that is required under Schedule 3 of the reliability provisions of our licence conditions with benefits that are likely to accrue under the STPIS. This was not undertaken in our initial proposal because we had adjusted the proposed targets to recognise this and other impacts. In adopting the general approach of the draft decision for setting STPIS targets, we have included an offset to our reliability expenditure to recognise this effect.

Revised reliability expenditure proposal

Ausgrid forecasts a requirement for capital expenditure for reliability remediation of $19.5 million ($2013/14, excluding overheads), but with an offset of $6.6 million to account for the proportion that would be expected to be funded by marginal STPIS revenue. As a result the amount to be included in the standard control capital expenditure items for revenue modelling is reduced by the STPIS offset.

Attachment 5.13 details the revised reliability investment plan, including the details of the calculation of the STPIS offset.

We note that any relationship between the STPIS and our expenditure forecasts is predicated on the connected nature of the STPIS parameters, especially the targets, and the provision of sufficient revenue to fund our revised expenditure proposal. If there are any significant variations to our revised proposal in the final determination, these assumptions may no longer hold. In the case of our Reliability Investment Plan, this may entail significantly larger expenditures on poor performing feeders and no offset from STPIS revenue.

This was supported by Jacobs in their analysis of the reliability impacts if the AER's draft decision was to be adopted (Attachment 1.01):

> *Specific cuts to reliability capex will prejudice NNSW's ability to meet Schedule 2, 3 and 5 of licence conditions even if not making a large impact on STPIS. Reduction of programmes targeting poorly performing feeders will have a direct negative impact on supply reliability. However, due to the small proportion of these programs within the overall capital program and also due to the focus of these programs on individual poorly performing feeders, rather than overall system reliability, the STPIS will not generate savings or penalties equivalent to the cost of the works. Therefore, these programs must be funded in addition to any STPIS benefits/penalty.*[195]

Our revised forecast of reliability investment expenditure is shown in Table 23 below.

Table 23 – Reliability capital – revised expenditure forecast ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Reliabilityexpenditure	2.1	4.5	4.5	4.3	4.3	**19.5**
STPIS offset	-	-0.6	-1.0	-2.2	-2.8	**-6.6**
Net capital expenditure	**2.1**	**3.9**	**3.4**	**2.1**	**1.5**	**13.0**

Note: Numbers may not add due to rounding.

[195] Attachment 1.01 - Jacobs - Reliability Impact Assessment, p. 9

5.7 Non-network capital investment

The draft decision

The draft decision identified Ausgrid's forecast non-network capital expenditure as $307.6 million ($2013/14, real excluding overheads). It did not accept this proposal and instead included an amount of $279.2 million. The draft decision used trend analysis and found that "*Forecast capex for each category is relatively smooth and at historically low levels across the 2014–19 period, with the exception of buildings and property capex*[196]". Further, the buildings and property expenditure comprised the largest component at $142.2 million.

The draft decision's more detailed review of the buildings and property forecast resulted in an alternative estimate of $113.8 million based on a delayed schedule and an expectation of reduced project costs. The other components were not adjusted in the alternative estimate for the non-network category.

Ausgrid's response

Ausgrid does not agree with the alternative estimate in the draft decision.

The draft decision inferred the values used to assess the non-network capital expenditure from the PTRM model data in the RIN due to anomalies in the expenditure summary table[197]. The correct value for direct costs in this category of our initial proposal was $333.4 million ($2013/14, direct costs only). The difference arises from the method used to net out overheads from the PTRM data. The corrected data was provided to the AER on 10 December 2014.

The draft decision proposed changes only to the buildings and property category of non-network capital expenditure. It asserts that Ausgrid's forecast buildings and property capital expenditure is front-loaded. The timing of the three major projects is driven by a combination of end of lease arrangements and urban growth imperatives driving a need to relocate. Delaying of the proposed investment timing in the way suggested in the draft decision would lead to a requirement to fund a lease extension (assuming one was available) from operating expenditure. Ausgrid's property strategy to reduce its presence within the Sydney CBD and relocate its staff to the adjacent metropolitan depots relies on the timing of the proposed projects. Ausgrid's response to the AER's question on this matter (AER Ausgrid 031) on the 8th September 2014 provided the evidence supporting this position.

The draft decision also claims Ausgrid's forecast buildings and property capex has been overstated due to the likelihood of future changes in project timing, scope and cost. Ausgrid's forecasts follows on from a careful consideration of project timing, scope and cost, and input from independent external review of our requirements. These processes have significantly refined the initial plans and resulted in the forecast expenditure as presented in our initial proposal. Other key considerations include the size and make up of Ausgrid's ongoing workforce and logistics requirements to maintain its Network and this is reflected in the submission.

On this basis, Ausgrid disagrees with the assertions in the draft decision regarding changes to our property and buildings expenditure forecast, and our revised proposal reflects the estimate provided in the initial proposal.

Revised non-network expenditure proposal

Ausgrid's revised forecast for non-network capital expenditure is $384.2 million ($2013/14, direct cost). This includes the following components:

Table 24 – Non-network capital – revised expenditure forecast ($ million, 2013/14, excluding overheads)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
IT & communications	15.3	14.6	18.7	20.2	16.2	**85.1**
Motor vehicles	10.9	8.6	9.6	12.2	13.0	**54.3**
Buildings and property	33.6	60.3	44.4	24.0	2.0	**164.3**
Plant and tools	7.3	3.6	5.2	4.2	4.5	**24.8**
Non-network SCADA and network control	8.6	18.7	8.3	9.2	10.9	**55.6**
Total non-network	**75.8**	**105.8**	**86.2**	**69.7**	**46.6**	**384.2**

Note: Numbers may not add due to rounding.

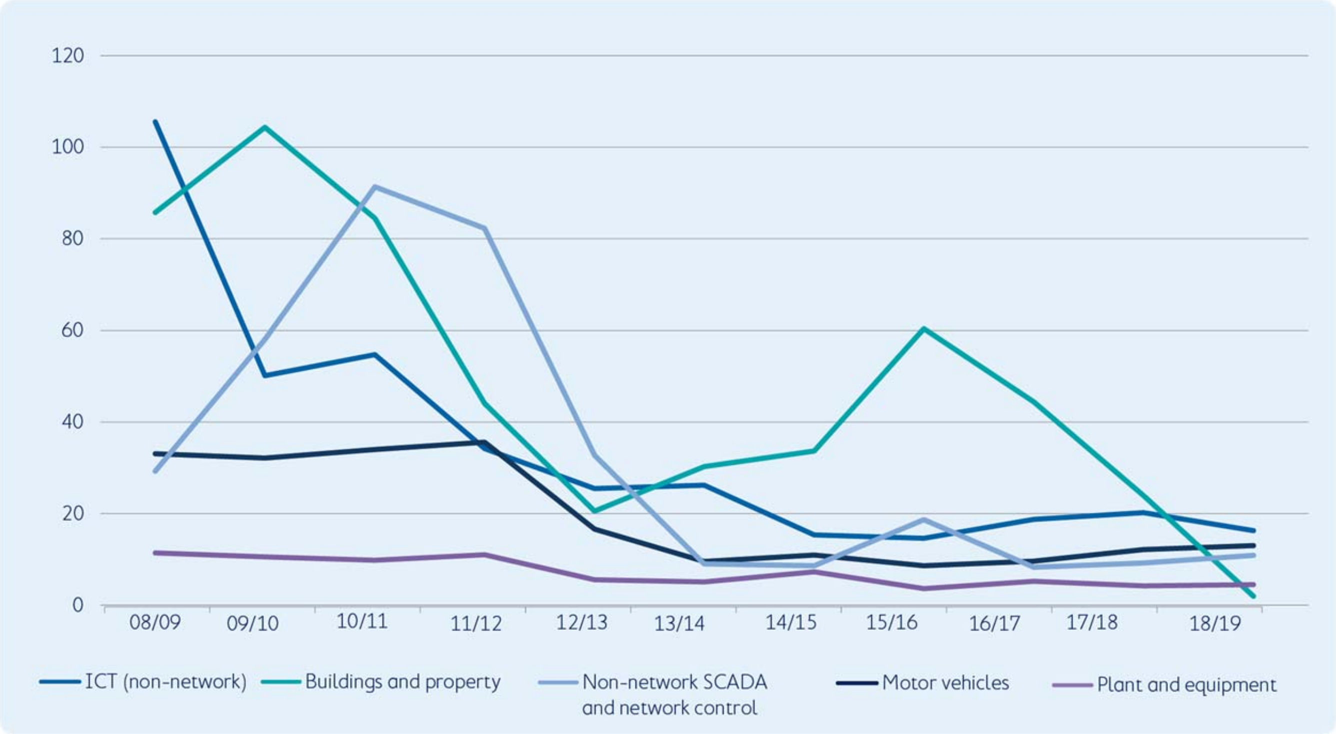
[196] AER draft decision – Attachment 6: Capital expenditure, p. 6-76

[197] AER draft decision Ausgrid distribution determination - Ausgrid 2014 - Consolidated Capex Forecast model - November 2014.xlsx, Sheet 'Capex by Purpose', cell C82

This revised proposal is consistent with our initial proposal but adds the category of SCADA and network control expenditure to the non-network category. In the RIN data that accompanied our initial proposal, this category had been allocated across our network expenditure categories due to a misunderstanding of the RIN requirements. As noted in the relevant sections this was one reason the values for replacement and augmentation expenditure were inflated in the draft decision. The treatment in this revised proposal is in accordance with the presentation in our technology plan submitted as part of our initial regulatory proposal, and with the RIN definitions. The proposed expenditure in the non-network SCADA and network control is as described in the technology plan attached to our initial proposal.

The chart below presents the revised data in the same format as used in the draft decision[198], demonstrating that the conclusion drawn from the trend analysis that the forecast expenditure is reasonable relative to historic rates of expenditure hold true for this additional category as they continue to do for the remaining items within non-network capital expenditure.

Figure 21 – Non-network capex by category ($ million, 2013/14)



5.8 Capitalised overheads

The draft decision

The draft decision identified Ausgrid's forecast capitalised overheads as $729.2 million ($2013/14). It did not accept this proposal and instead included an amount of $477.3 million. The draft decision used trend analysis to assess the historical level of capitalised overheads and found Ausgrid's proposal reflected historical trends and was "*consistent with its proposed total forecast capex*[199]".

The draft decision calculated an average rate of overheads (separated for distribution standard control and dual function capital expenditure) for each year based on Ausgrid's proposal. It then multiplied the alternative forecast direct expenditure by this rate to arrive at its alternative estimate for capitalised overheads.

Ausgrid's response

Ausgrid agrees that the forecast for capitalised overheads should be consistent with historical levels and vary partly in proportion to the change in overall capital expenditure. Our own estimates recognise that there are some fixed elements of overheads, but that a significant proportion of costs are variable with the size of the capital program. Because we do not accept the draft decision regarding overall capital expenditure, we are proposing different values for capitalised overheads in our revised proposal.

[198] AER draft decision – Attachment 6: Capital expenditure, Figure A-20, p. 6-76

[199] AER draft decision – Attachment 6: Capital expenditure, p. 6-81

Revised capitalised overheads proposal

Ausgrid's revised forecast for combined capitalised overheads is $645.0 million ($2013/14), a reduction of $115.8 million as a direct result of a lower forecast of direct capital expenditure and by improved productivity and management of overheads. The figure below shows this revised proposal as a proportion of total capital expenditure using the same approach as the draft decision[200] to provide a ready comparison. Figure 22 shows an increasing profile simply because of the reduction in total capex (i.e. the denominator).

Figure 22 – Capitalised overheads as a proportion of total capital expenditure

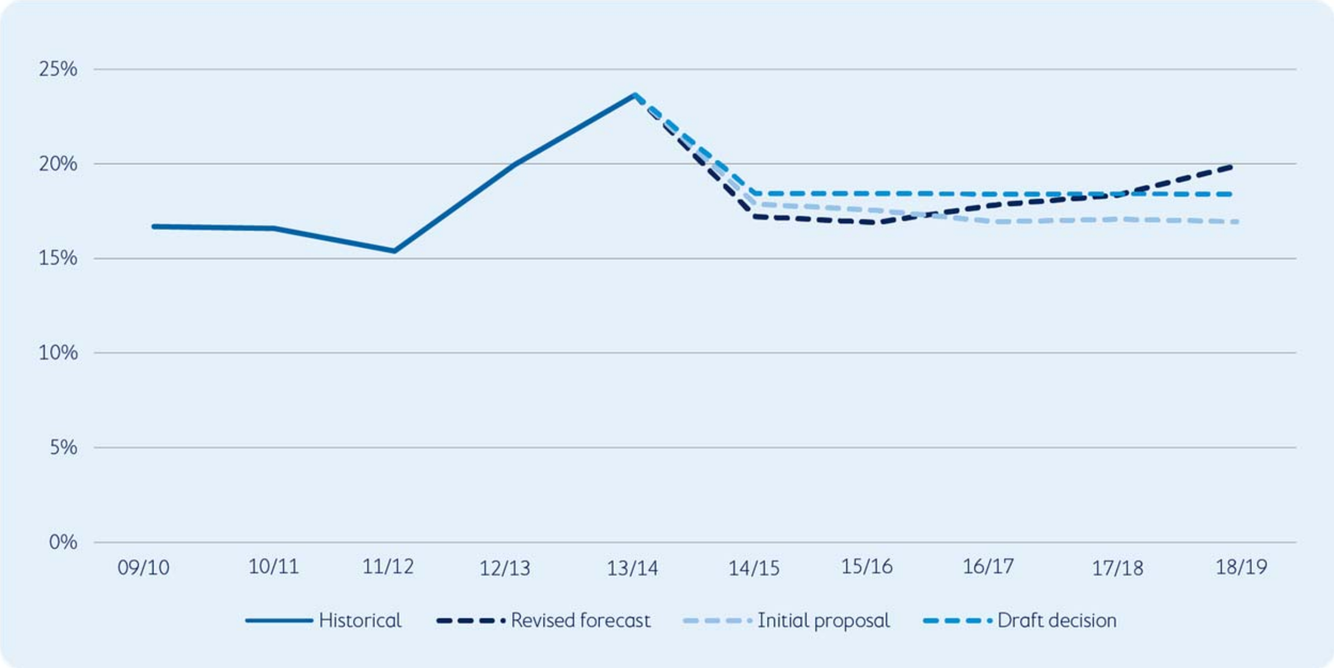


Table 25 – Capitalised overheads – revised proposal ($ million, 2013/14)

Plan	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Network overheads	118.9	134.2	132.2	120.5	111.5	**617.6**
Corporate overheads	4.8	4.6	6.0	6.5	5.4	**27.4**
Total	**123.8**	**138.9**	**138.4**	**127.0**	**116.9**	**645.0**

Note: Numbers may not add due to rounding.

5.9 Demand management

The draft decision

In the capital expenditure attachment, the draft decision takes a position to not include any specific reference to demand management in either the opex or capex forecasts, relying on a view that the incentives in the capital expenditure sharing scheme and the provisions in the National Electricity Rules are sufficient to drive efficient outcomes.

In the operating expenditure chapter the draft decision specifically rejects consideration of a step change in operating costs to reflect an increased program of proactive, broad based demand management.

Ausgrid's response

Demand management (DM) is a key component in the efficient management of an electricity network. *"The extent to which the DNSP has considered, and made provision for, efficient and prudent non-network alternatives"*[201] is one of the capex factors to be

[200] AER draft decision – Attachment 6: Capital expenditure, Figure A-22, p. 6-81

[201] NER, cl 6.5.7(e)(10)

considered by the AER under the National Electricity Rules. Ausgrid's proposed portfolio of demand management activities, as detailed in our initial proposal, is a program of prudent and efficient expenditure to lower customer demand and defer capital expenditure in the long term interest of customers. We propose to resubmit our program as per the initial proposal.

The draft determination's rejection of both the replacement of the D-factor incentive with the proposed demand management benefit sharing scheme (DMBSS) and the broad based demand management program is a backwards step in the development of demand management. The draft determination has failed to recognise the ongoing absence of any actual incentive for DNSPs to pursue demand management as a solution to network needs, the value of demand reductions to the wider energy supply chain and the need to invest to assist customers in responding to price signals and lower their peak demand. Reliance on a modest innovation fund and the RIT-D will not be sufficient to build such capacity and will result in significantly less demand management than is cost effectively viable and higher levels of augmentation capex in the following regulatory period.

Refer to section 6.7 of Chapter 6 for our response to the draft determination on Ausgrid's broad based demand management program. We recognise that the pervasive nature of demand management means that elements appear under operating expenditure, capital expenditure and application of incentives. It is inculcated into demand forecasts, part of underlying area planning and applied in top-down adjustments to our HV distribution model. For this reason we have brought together a discussion of all aspects of demand management across the revised proposal in a single document (Attachment 5.14) to enable the intertwined aspects to be understood more easily and considered more effectively. This demonstrates how demand management expenditure represents:

(1) the efficient costs of achieving the capital expenditure objectives;

(2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

Revised demand management proposal

In formulating our revised proposal we have:

- re-assessed our DM program in line with the low levels of augmentation arising from the revised spatial demand forecast, and included these effects in our capital expenditure requirements;
- reviewed and confirmed that the level of targeted spatial DM activity is consistent with the outcomes from the previous regulatory period, based on its application to HV distribution plans;
- verified the business case for the optimised broad-based DM program such that a positive NPV is returned in 6.5 years and the total NPV through to 2024 is $31 million; and
- confirmed that the optimised broad-based DM program is complementary with cost reflective tariffs.

The AER did not accept Ausgrid's proposal for an investment in broad based demand management to lower customer demand and defer capital expenditure in the long-term interests of customers. The draft determination rejected the proposed program on the basis that the introduction of cost reflective pricing would deliver price signals enabling customer response sufficient to undermine the business case for broad-based demand management.

Ausgrid has dealt with the concerns raised in the draft determination in section 6.7 of Chapter 6 and has re-proposed the program in an unchanged form. Importantly, this means we have retained the effect of the broad-based DM program in our demand forecasts, which has flowed through to our augmentation capital program. Because they are embodied as reductions in the demand forecast, these offsets to capital expenditure are not visible in the augmentation program models.

We have also retained our expectation that a small amount of the remaining augmentation program in the HV distribution plan will be able to be deferred using targeted local DM projects. We have modelled this based on the historic percentage of growth driven expenditure in this category that we have sucessfuly deferred using DM, and the average costs of previous projects.

Further detail about these interactions is contained in Attachment 5.14.

5.10 Real cost escalation

The draft decision

The draft decision rejected Ausgrid's forecasts for materials cost escalation and substituted them with zero real cost escalation. The reasons cited were concerns with the methodology, inconsistency of forecasts from different economists and the predictive accuracy of futures contracts.

The draft decision rejected Ausgrid's proposed labour cost escalation and substituted values based on the average of Deloitte Access Economics and Independent Economics wage price index (WPI) forecasts for the EGWWS sector. It considered an averaging approach that takes into account the consultant's forecasting history, if available, to be the best methodology for forecasting labour price change.

The draft decision accepted the construction cost escalators proposed in our initial proposal.

Ausgrid's response

Ausgrid does not accept the draft decision's alternative forecast of zero real materials cost escalators.

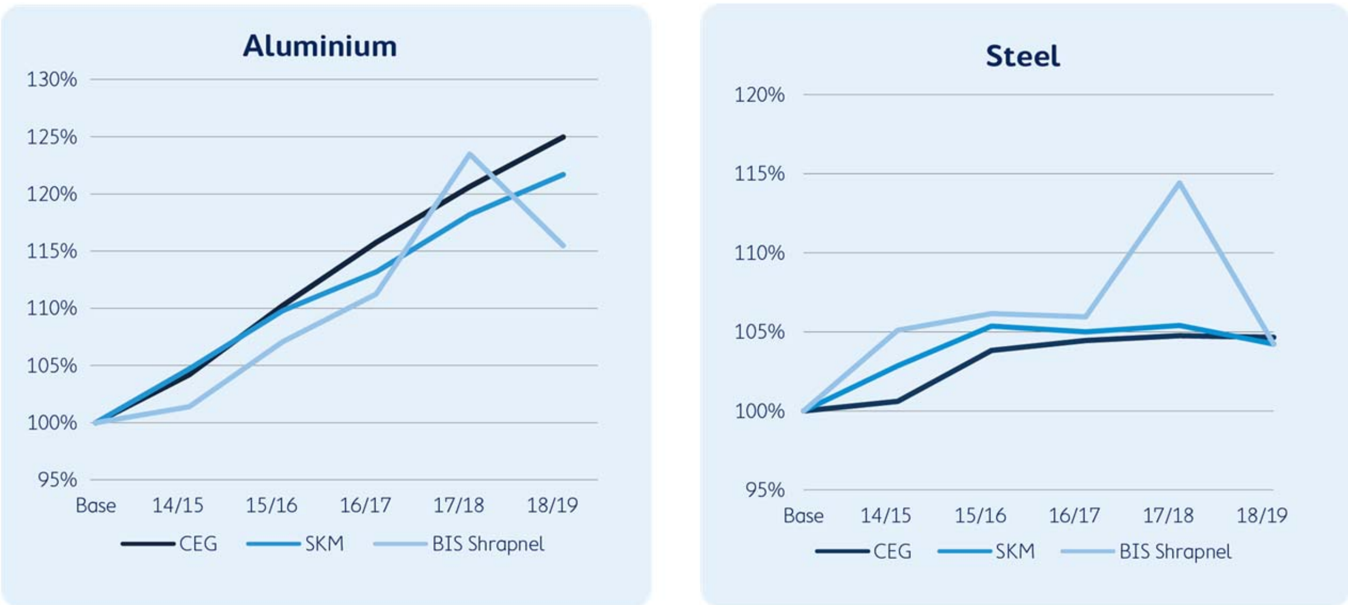
The draft decision notes "Relevantly, we must be satisfied those forecasts reasonably reflect a realistic expectation of cost inputs required to achieve the capex objectives.[202]" If the cost inputs proposed by Ausgrid represent a realistic expectation the AER should accept Ausgrid's proposal. Demonstrably the substitution of zero cost escalation for Ausgrid's proposed approach does not make a material difference to the overall estimate of cost inputs. When applied to the overall capital expenditure forecast, the alternative estimate delivers a difference of only $4.28 million or less than one tenth of a per cent. On this basis we would argue that the estimate of cost inputs derived from the draft decision is almost identical to that proposed by Ausgrid, it therefore demonstrates that Ausgrid's proposal represented a realistic estimate and should have been accepted.

We do not accept that there are no proven links between Ausgrid's material costs and commodity prices as these commodity price pass throughs are commonly embedded in commercial contracts with suppliers and this was demonstrated in our previous regulatory submissions and accepted by the AER in the 2009-14 determination. These commercial arrangements, economic forecasts and futures contracts represent realistic attempts to manage uncertainty and expected materials price risk.

The draft decision makes much of the variations between different approaches to material price forecasting by SKM, BIS Shrapnel and CEG. We contend that the draft decision is erroneous when it concludes that because different views and approaches are possible that all forecast expectations of cost inputs are unrealistic and unreasonable. Forecasting the future is by its nature challenging and not guaranteed to be accurate but professional forecasts still reflect the best and most realistic expectations.

The range of year-to-year forecasts from the three consultants in TableD-3[203] is used to suggest that the forecasts have such a range that they are therefore unreliable. However, when viewed as cumulative price changes it is clear that each of the consultants has an almost identical view of the change over the five years, but different expectations of volatility. For example, the figures below show the progressive escalation index for each of the consultant's forecasts for Aluminium and Steel.

Figure 23 – Real material input cost escalation forecasts (%)



It is clear from these that the different consultants do not have markedly different views of the future, despite there being some disparity in the path. These comparisons also suggest that zero escalation could not be supported as a more reasonable estimate.

Ausgrid chose Competition Economists Group (CEG) to provide its material cost escalation estimates because they are suitably qualified economists with experience and understanding of the sector.

The draft decision also suggests *"We consider that electricity service providers can mitigate the risks associated with changes in material input costs by including hedging strategies or price escalation provisions in their contracts with suppliers of inputs (e.g. by including fixed prices in long term contracts).[204]"* While such an approach may be theoretically possible, it is neither common commercial practice, nor a realistic option. Pushing escalation risk to suppliers does not insulate a DNSP from the risk, it simply crystallises the expected value in the up-front price.

[202] AER daft decision - Attachment 6: Capital Expenditure, .p 6-102

[203] AER draft decision - Attachment 6: Capital Expenditure, Table D-3, p. 6-11

[204] AER draft decision - Attachment 6: Capital Expenditure, p. 6-105

The alternative estimate in the draft decision implicitly adopts the CPI as the nominal material cost escalator. The Consumer Price Index is based on a weighted basket of household goods, and the draft decision offers no justification, consultation or analysis to support this contention.

With regard to labour and construction cost escalators, Ausgrid endorses the draft decision to retain construction cost escalators as proposed, and accepts the proposed approach to labour cost escalation.

Revised cost escalation proposal

For our revised proposal, we have refreshed the CEG estimates of material cost input real escalation to reflect the latest available information and have adopted the draft decision's approach to labour escalation. Ausgrid believes this represents a reasonable and realistic expectation of cost inputs. The escalations used are shown in Table 26 for each item. These are used in the cost escalation inputs and model spreadsheet in Attachment 5.15.[205]

Table 26 – Revised proposal - real cost escalation (%)

Plan	2014/15	2015/16	2016/17	2017/18	2018/19
Aluminium	12.9	1.5	1.0	2.7	2.8
Copper	-2.6	-1.6	-1.4	0.8	1.1
Oil	-12.1	-1.6	1.1	1.0	0.9
Steel	-6.0	-0.4	2.0	0.7	1.0
Construction	0.7	1.1	-0.2	0.1	0.8
Labour*	0.89	0.87	1.40	1.62	1.44

Note: Numbers may not add due to rounding.
*based on AER's approach in the draft decision.

5.11 Summary of revised capital expenditure proposal

Ausgrid's revised capital expenditure proposal is 15% lower than the initial proposal. We have made these adjustments in response to changes in input information, improvements in our analytical and investment decision making methodologies, forecast improvements in project and labour efficiency and in consideration of feedback on our initial proposal from stakeholders, the draft decision and the AER's consultants. We also refer the AER to a statement prepared by Group Executive Network Strategy (Attachment 5.17) which provides further information on the outcomes of the prioritisation process.

In this document we have analysed the outcomes and reasoning in the draft decision. In cases where the analysis was based on flawed or misinterpreted input information we have attempted to correct the information or provide clearer explanations and presentation of our proposal. In cases where we view the analytical techniques as inappropriate for the purpose they were used for, we have identified those occasions and in most cases developed or offered alternative views and methodologies. In cases where legitimate concerns were raised with our approach, we have developed and adopted results from new and amended techniques, and incorporated the results into our revised proposal. In cases where the draft decision made assumptions to develop alternative estimates, we have pursued more detailed analysis and replaced those assumptions with actual data and prepared fresh estimates of the need for capital expenditure.

In addition to the range of approaches focussed on ensuring our program is efficient in terms of the activities undertaken, we have recognised that a range of initiatives currently being implemented will deliver additional improvements in cost efficiency. We have incorporated those as top down adjustments to our overall revised capital expenditure forecast. The two key elements here are project scope efficiencies and unit cost improvements. The progressive development of our investment governance framework has resulted in improved challenge practices before major projects are submitted for approval. The example of Cessnock zone substation was quoted in our initial proposal[206], where a design scope review eventually led to a 30% reduction in cost. This scale of improvement has not proven achievable in most projects, but we now have a track record to draw on that has enabled us to estimate a top down adjustment for total cost of major projects that are still in the planning stage. These have effect in the later

[205] Attachment 5.15 – Cost escalation updates

[206] Ausgrid's Regulatory Proposal, May 2014, p. 38

years of the period (because the projects to which it can be applied are still in development), but we have applied a top-down adjustment to major project expenditure that recognises an overall cost reduction rising to 5% in 2019.

Other initiatives seeking improvements in unit costs that are primarily focussed on operating costs are also expected to have some flow on benefits to the capital expenditure profile. This includes improved labour utilisation strategies and the blended delivery model described in the delivery strategy (Attachment 5.05). While these will take some time to flow through to the capital expenditure profile, we have estimated a cumulative reduction rising to 3% of overall capital expenditure by 2019.

Therefore, Ausgrid has presented a revised proposal that meets the capital expenditure criteria, being expenditures that reflect:

(1) the efficient costs of achieving the capital expenditure objectives;

(2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives

Revised capital expenditure proposal – driver view

Our revised capital expenditure proposal is presented in the table below in a form that reflects the preferred approach in the draft decision. We have reconciled it to the same view of our initial proposal for comparison.

Table 27 – Revised capital expenditure proposal by driver ($ million, 2013/14)

	Initial proposal	Revised proposal	Difference	%
Replacement & duty of care	2,707	2,197	-510	-18.8%
Connections	194	213	19	9.8%
Augmentation	399	303	-96	-24.1%
Reliability	28	20	-8	-28.6%
Non-network	333	384	51	15.3%
Overheads	760	645	-115	-15.1%
STPIS offset	0	-7	-7	0%
Total expenditure	**4,421**	**3,756**	**-665**	**-15.0%**
Capital contributions	522	477	-45	-8.6%

Note: Numbers may not add due to rounding.

Revised capital expenditure proposal – plan view

For comparison with the documentation provided for our initial proposal, we have also presented the same information in the plan view we used in our initial proposal.

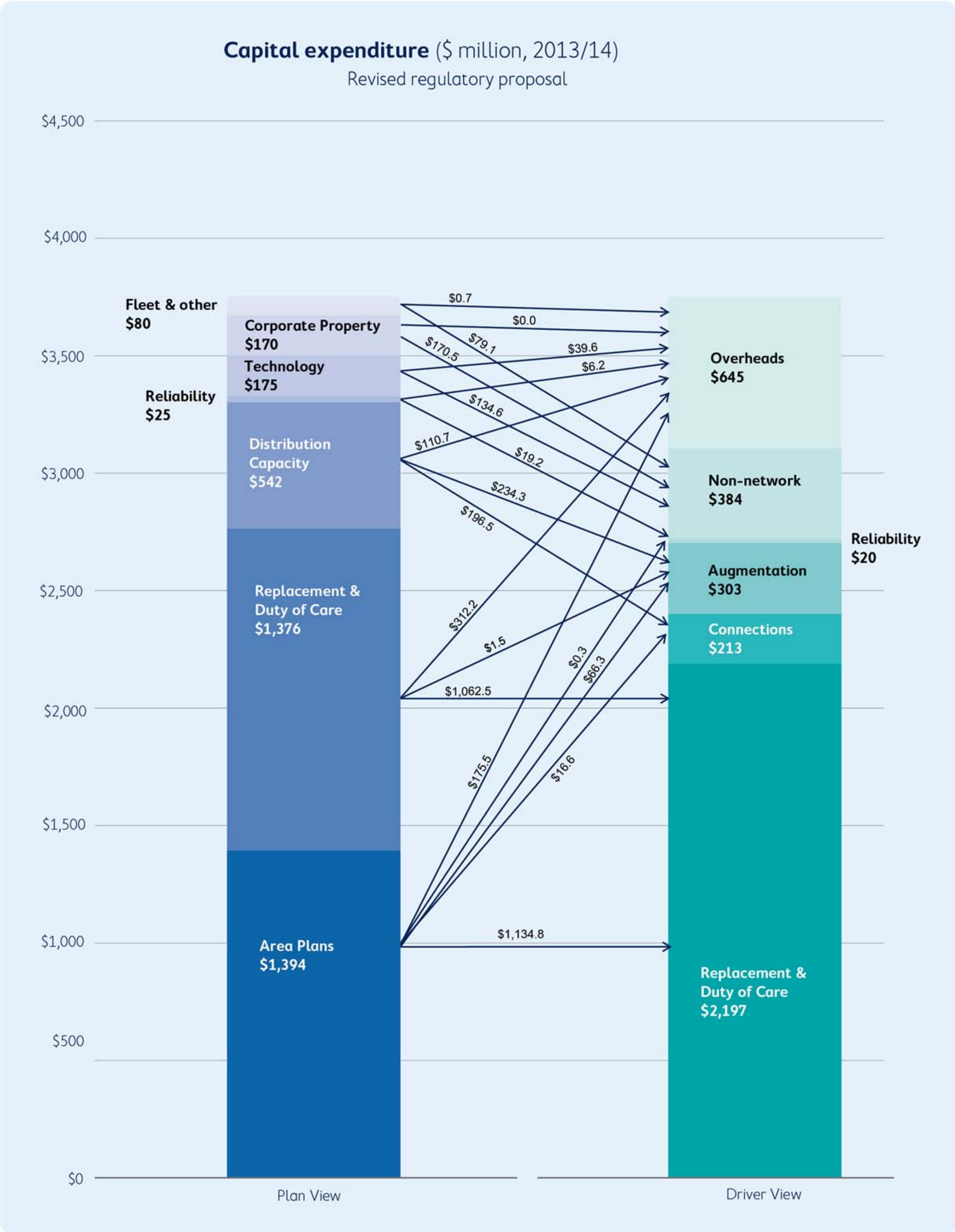
Table 28 – Revised capital expenditure proposal by plan ($ million, 2013/14)

	Initial proposal	Revised proposal	Difference	%
Area plans	1,583	1,394	-189	-12.0%
Replacement and duty of care plans	1,776	1,376	-400	-22.5%
Distribution capacity plan	598	542	-56	-9.4%
Reliability investment plan	28	25	-3	-10.5%
Technology plan	182	175	-7	-3.9%
Corporate property plan	173	170	-3	-1.6%
Fleet & other plans	80	80	-1	-0.9%
STPIS offset	0	-7	-7	
Total expenditure	**4,421**	**3,756**	**-665**	**-15.1%**
Capital contributions	522	477	-45	-8.6%

Note: Numbers may not add due to rounding.

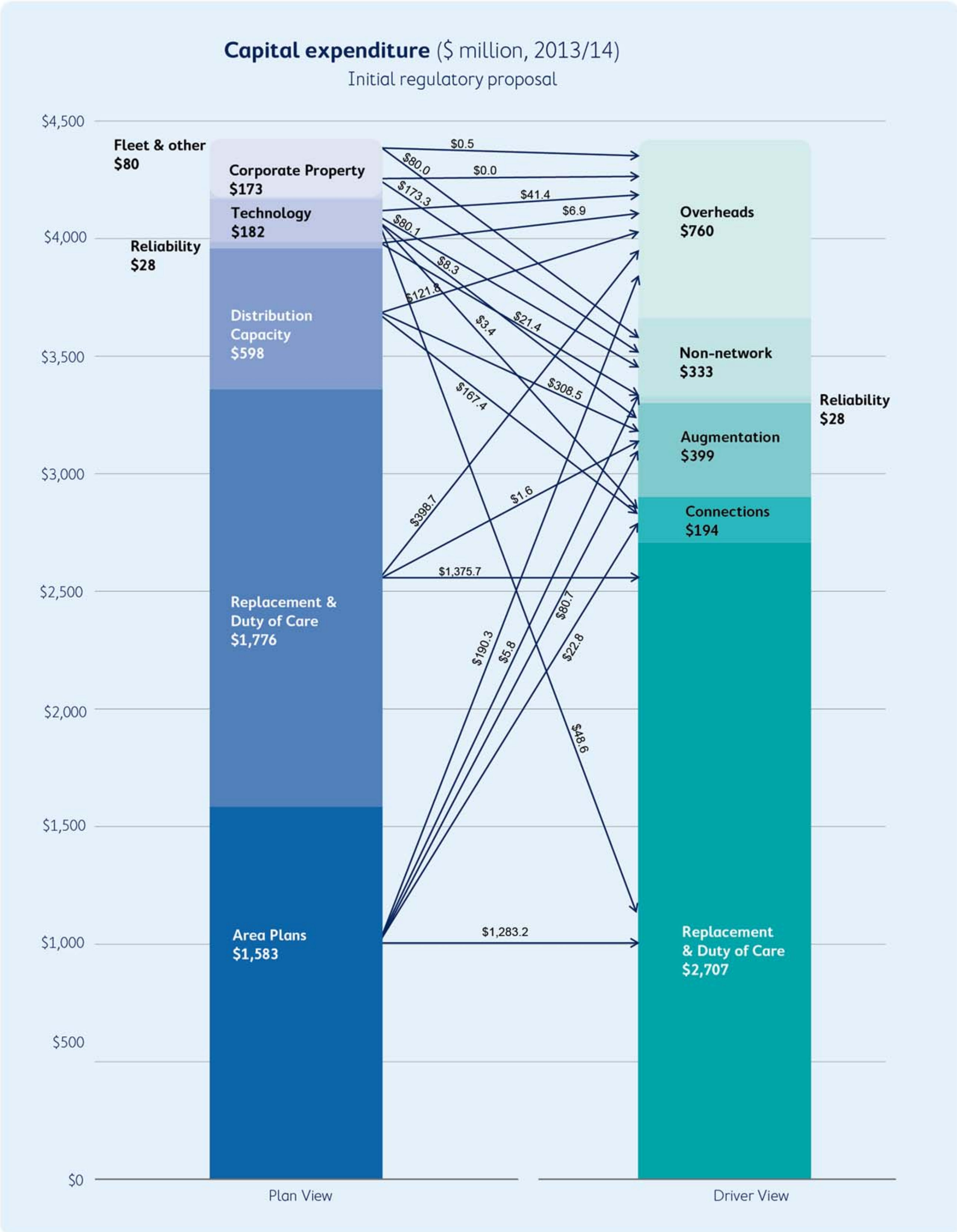
In order to provide greater transparency regarding the connection between our plan view and the driver view, we have prepared cross tabulations and presented them diagrammatically in Figure 24 and Figure 25.

Figure 24 – Map of plan view to driver view – Revised regulatory proposal (Jan 2015)



Note: Numbers may not add up due to rounding. This chart represents Ausgrid proposed mapping for this revised proposal.

Figure 25 – Map of plan view to driver view – Initial regulatory proposal (May 2014)



Note: Numbers may not add up due to rounding. This chart represents the mapping used in the Reset RIN provided to the AER on 10 December 2014.

6. Forecast operating expenditure

We are proposing a revised operating expenditure program of $2.7 billion ($2013/14) for the 2014-19 period to support our business activities and maintain the reliability, safety and security of our distribution system. This is a 5.8% reduction on the forecast included in our initial proposal.

In our initial proposal, we provided the AER with information to demonstrate the need and efficiency of our forecast opex. Our expenditure sought to promote the long term interests of customers by providing safe, reliable and affordable services over the 2014-19 period. A key element of our proposal was to incorporate substantial efficiencies from our cost saving programs that we commenced in the 2009-14 period. More importantly, our forecast opex ensures any upward pressure on our cost base is managed appropriately so that customers will not be adversely impacted.

The AER's draft determination rejected our proposed expenditure and substituted a substantially lower amount. The AER's decision stems from its assessment technique, which involved extensive reliance on benchmarking analysis.

We have sought to reflect on whether revisions are required to incorporate the matters raised in the AER's decision and its reasons for it. We have retained most elements of our initial proposal rather than revise for the AER's decisions or reasons. In this respect we consider that the AER misconstrued its task under the rules, and has not undertaken a proper assessment of our proposed opex. Further, we do not agree with the AER's position and comments in respect to Ausgrid's labour practices, loss of synergy costs and our redundancy costs. As a result we have not revised our position with respect to these matters in our revised proposals.

We have however accepted the AER's decision on labour cost escalation and have incorporated the AER's draft decision in the revised forecast opex, noting that these will be updated for the latest data at the time of the AER's final determination. Similarly, we have revised our proposal to incorporate for the latest information and data.

Importantly incorporating for the latest information and data has resulted in improved operating efficiency, above that which was forecasted in our initial proposal. In particular:

- This improved forecasted operating efficiency has resulted in an operating cost forecast for the 2014-19 period which is $163.5 million ($2013/14) lower than originally forecasted in the initial proposal.
- The improved operating efficiency includes a progressive improvement in labour productivity that averages 6% p.a. over the five year determination period. This reflects a forecast labour productivity improvement of 26.6% by the end of the regulatory period, whilst ensuring we continue to provide a safe and reliable network for our customers.
- We have also incorporated updated material cost escalation from the CEG and adopted the AER's draft determination in regard to labour cost escalation.

6.1 Revised proposal

Our revised proposal for standard control services opex expenditure for the 2014-19 regulatory control period is $2,679.34 million as shown in Table 29 below.

Table 29 – Revised forecast operating expenditure over 2014-19 ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Ausgrid's original forecast	565.1	566.2	574.2	568.9	568.4	**2,842.9**
AER's draft decision	337.5	342.2	349.8	343.2	349.2	**1,722.0**
Ausgrid's revised forecast	**528.4**	**553.2**	**536.1**	**531.7**	**529.9**	**2,679.3**

Note: numbers may not add due to rounding

We have structured this chapter as follows:

- Section 6.2 sets out the framework in the National Electricity Rules and Law that the AER must apply in making its constituent decision for opex.
- Section 6.3 provides a summary of how our initial proposal addressed the framework, including how our proposed opex was determined so as to achieve opex objectives, and how this satisfies the opex criteria with regard to the factors.
- Section 6.4 provides a summary of the AER's decision including its assessment methods, its reasons for rejection, its basis for substitution and how it sought to address the rules framework.

- Section 6.5 notes our concerns that the AER misconstrued its task under the framework and why this has not enabled it to make a proper assessment of our proposal under the opex criteria. We show that the AER has misinterpreted its powers following amendments to the rules and law in 2012. This has manifested in 3 ways the AER has been misdirected in making its decision:
  - The AER adopted its own alternative estimate as a starting point, and used the estimate as a threshold for accepting our proposal. We consider the AER should have undertaken a more in-depth review of our proposal, rather than apply an alternative estimate that could not fully account for the capex criteria and factors.
  - The AER has placed undue weight on benchmarking analysis in reviewing our proposal and in making its decision to reject and substitute our forecast. The AER has used its benchmarking results as a deterministic tool in both assessing Ausgrid's proposed forecast opex and in calculating a substitute forecast.
  - The AER's substitute allowance has been derived using benchmark information of other DNSPs, and has therefore not considered our activities, drivers or circumstances. We consider that the AER should have undertaken a reasonableness check of its substitute amount by assessing the implications to our operations from its decision.
- Section 6.6 sets our out analysis of the AER's benchmarking results.
- Section 6.7 addresses other substantive issues raised in the AER's draft decision.
- Section 6.8 notes that in reviewing the matters raised in the AER's decision, we have examined whether any revisions are required to incorporate new information or data since submitting the proposal. We maintain all elements of our original proposal in relation to forecast opex to the extent that information has been updated to take into account our latest forecast performance, including updated forecast redundancy costs and savings reflective of higher than previously forecasted productivity improvement and the application of cost escalators as per the AER's draft decision, noting that this will be updated by the AER closer to the final determination. Finally, we reiterate our revised proposal better satisfies the opex criteria with relation to the opex objectives, compared to the AER's decision. We undertake a review of our activities and show that the AER's proposed cut would reduce our ability to maintain our network, undertake prudent vegetation management, support our system activities, and deliver on our corporate obligations.

6.2 Framework for AER's decision

The rules require the AER to make a number of constituent decisions as part of its distribution determination. Clauses 6.12.1(3) and 6.12.1(4) relate to the AER's decisions on the forecast capex and forecast opex proposed by a DNSP in its building block proposal. The AER either:

(i) acting in accordance with clauses 6.5.6(c) and 6.5.7(c), accepts the total of the forecast opex and capex for the regulatory control period that is included in the current building block proposal; or

(ii) acting in accordance with clauses 6.5.6(d) and 6.5.7(d), does not accept the total of the forecast opex and capex for the regulatory control period that is included in the current building block proposal, in which case the AER must set out its reasons for that decision and an estimate of the total of the Distribution Network Service Provider's required opex and capex for the regulatory control period that the AER is satisfied reasonably reflects the expenditure criteria, taking into account the expenditure factors.

In making its decision, the AER is guided by the objectives, criteria and factors in the rules. In interpreting these requirements, it must also consider the overall principles of assessment that have been described by the rule maker, the Australian Energy Market Commission (AEMC) in recent rule determinations. Each of these areas is discussed in the following sections.

Objectives criteria and factors

The rules set out a framework such that Ausgrid is required to propose total opex that Ausgrid considers is needed to produce the outputs or outcomes that are encapsulated in the rules. These outputs/outcomes are specified in clause 6.5.6(a) and 6.5.7(a) of the rules and are termed the operating and capital expenditure objectives (together expenditure objectives).

Clause 6.5.6(a) and 6.5.7(a) requires Ausgrid to include in its building block proposal the total forecast opex and capex for the 2014-19 period which Ausgrid considers is required to achieve each of the expenditure objectives[207].

[207] These objectives are: (1) meet or manage the expected demand for standard control services over that period; (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; and(4) maintain the safety of the distribution system through the supply of standard control services. (Objective 4)

The AER is required to make a decision on the total forecast expenditure proposed by Ausgrid. The rules provide that the AER must accept the forecast expenditure included in Ausgrid's building block proposal if the AER is satisfied that the total forecast expenditure reasonably reflects the expenditure criteria. These expenditure criteria are:

(1) the efficient costs of achieving the operating expenditure objectives; and

(2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

In deciding whether or not the AER is satisfied that Ausgrid's proposed total forecast expenditure reasonably reflects each of the expenditure criteria, the AER must have regard to the expenditure factors[208].

Changes to the NER in 2012

As we noted in Chapter 1 above, there was no major shift in the regulatory framework for assessing expenditure forecast resulting from the 2012 rule change. We demonstrated that the existing framework in the rules that were applied to the making of our 2009-14 determination remained largely intact. This included maintaining the structure of the objectives, criteria and factors.

At the time, the AEMC also clarified the process that the AER should follow when making its decision on expenditure forecasts. The AEMC emphasised the following key principles underlying the assessment process:[209]

- **Assessment process must start with a DNSP proposal** - The 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.
- **The AER must accept a proposal that is 'reasonable'** - The criteria require that the AER must accept a proposal if it is reasonable. The AEMC noted 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.
- **Consider the probative value of materials** - 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.
- **The AER's assessment techniques in making its analysis are not limited** – While the NSP's proposal will in most cases be the most significant input into the AER's decision. Importantly, though, it should be only one of a number of inputs. Other stakeholders may also be able to provide relevant information, as will any consultants engaged by the AER. In addition, the AER can conduct its own analysis, including using objective evidence drawn from history, and the performance and experience of comparable NSPs. The techniques the AER may use to conduct this analysis are not limited, and in particular are not confined to the approach taken by the NSP in its proposal.
- **The test of 'reasonable' must equally apply to the substitute amount** - While the AER must form a view as to whether a NSP's proposal is reasonable, this is not a separate exercise from determining an appropriate substitute in the event the AER decides the proposal is not reasonable. Both the consideration of "reasonable" and the determination of the substitute must be in respect of the total for each of capex or opex. The AER, whenever it determines a substitute for a NSP's proposal, is not constrained by the capex and opex criteria from choosing the best substitute it can determine.

[208] The first three factors were deleted as part of the 2012 Rule change. The factors in the Rules are therefore as follows:(4) the most recent annual benchmarking report that has been published under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period; (5) the actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods; (5A) the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers; (6) the relative prices of operating and capital inputs; (7) the substitution possibilities between operating and capital expenditure; (8) whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4;(9) the extent the operating expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms; (9A) 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); (10) the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives; and (11) any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s); (12) any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is an operating expenditure factor.

[209] AEMC 2012, Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Final Position Paper, 29 November 2012, p.111-113.

6.3 Our initial proposal

As noted above, the starting point for the AER's assessment is our regulatory proposal. With this in mind, our initial proposal provided detailed information to demonstrate that our proposed opex was efficient and prudent. We outlined the drivers impacting our proposal, set out our prudent forecasting method, and demonstrated how our cost categories are necessary to provide standard control services.

Our initial proposal recognised that historical context was relevant to the AER's decision on forecast opex. We showed that in the lead up to the 2009-14 determination, Ausgrid was entering a period of renewal in the network to address legacy issues from under-investment in the past. Our proposed opex for the 2009-14 period recognised that our opex would need to increase in response to these circumstances.

At the time of the 2009-14 determination, the AER scrutinised our proposed opex in great detail. The AER made substantial reductions to our proposed opex based on its thorough assessment. The AER was satisfied that its substituted opex for the 2009-14 was the efficient opex that Ausgrid would need to deliver the opex objectives, based on a realistic expectation of the demand forecast and cost inputs of this period.

In addition to setting a forecast opex that it satisfies reasonably reflects the efficient and prudent opex that Ausgrid would need during the 2009-14 period, the AER also implemented a very powerful incentive termed the Efficiency Benefit Sharing Scheme on Ausgrid to incentivise reductions in opex over the period. Simply, this scheme penalises Ausgrid if Ausgrid were to spend above the annual efficient opex the AER determined for each year of the 2009-14 period.

Our actual expenditure in the 2009-14 period responded in a positive manner to the incentives developed by the AER. Table 30 shows the comparison of our actual opex for the 2009-14 to the efficient allowance approved by the AER.

Table 30 – Comparison of operating expenditure over 2009-14 ($ million, 2013/14)

	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Actual	598.5	584.4	645.1	520.8	581.2	**2,930.1**
AER's allowance	573.1	584.9	597.3	608.3	609.9	**2,973.5**
Difference	**25.4**	**-0.5**	**47.8**	**-87.5**	**-28.7**	**-43.4**

May not add due to rounding

Based on our response to the incentives set by the AER and the 2009-14 distribution determination approved by the AER, we considered that our actual costs in 2012-13 were an efficient starting point from which to develop an opex forecast. Similar to any prudent business, we need to consider our anticipated circumstances for the forthcoming period and as such we considered the drivers of costs in the 2014-19 period relative to our actual costs, with regard to our regulatory obligations and operating environment but also mindful of the impact of any opex increases on our customers. That is, we set out to achieve a forecast opex that would promote the long term interest of customers with respect to price, safety and reliability whilst also ensuring we are allowed a reasonable opportunity to recover at least the efficient costs we expect to incur in providing services to consumers.

In this context a central aspect of our proposal was to show how the proposed opex met the long term interests of our customers. We demonstrated the efficiency initiatives we had introduced in the 2009-14 period, which had led to significant cost savings compared to the efficient allowance determined by the AER. We also showed we had considered the level of efficiencies we could achieve in our circumstances, and how we had incorporated these into our forecasts to improve affordability for our customers.

Together with our contextual description, we also sought to demonstrate how our forecast of opex achieved the opex objectives, and satisfied the opex criteria in the rules with regard to the opex factors. We summarise below how our proposal met the framework under 6.5.6(a) of the rules, and refer the AER to Attachments 5.31 and 5.32 of our initial proposal.

Achieving opex objectives

Ausgrid included in the building block proposal a total forecast operating expenditure for the 2014-19 period that Ausgrid considers is required to carry out the necessary activities so as to achieve each of the opex objectives listed in clause 6.5.6(a) of the rules. This total forecast opex is made up a number of cost categories. These cost categories represent the costs of undertaking a set of interrelated activities and to operate the various systems necessary to achieve each of the opex objectives.

We have outlined above the components of our proposed total forecast opex for the 2014-19 period and demonstrate how these cost components are required to achieve each of the expenditure objectives listed in clause 6.5.6(a) of the rules. These costs are incurred to deliver the network business activities and outcomes specified by each of the expenditure objectives. Table 31 shows the opex cost groups of our total forecast opex.

Table 31 – Forecast costs and the opex objectives

Opex cost group and opex objectives achieved	Activities
Maintenance opex – achieve all opex objectives	Maintenance opex is required to undertake various activities on Ausgrid's electrical network. These includes vegetation management, inspection of the network, corrective maintenance, repair of asset breakdowns including those caused by nature (storms etc), testing of plants and tools used for maintenance tasks and engineering support. These activities, hence associated cost, are critical achieve all four opex objectives.
Operation and support – achieve all opex objectives	Operation expenditure are those costs incurred in undertaking the required activities to directly support the operation of Ausgrid's network system. Support expenditure is those necessary for the normal operation of Ausgrid as a business such as: a) ***Information, communication and technology*** – costs relating to the operation and maintenance of various IT technologies and telecommunication systems required for the effective operation Ausgrid's infrastructure and day to day operations. b) ***Property management*** – costs of various activities inherent in the ownership of properties (land and building) including the costs of complying with various legal obligations pertaining to this ownership such as land registration, land tax payments, council rates, water and electricity usage c) ***Network operations*** – costs pertaining to activities undertaken for customer operations, network control and engineering, planning and connection. • Customer operations – costs relating to the management, planning and reliability of the distribution network. This includes facilitating new connections, responding to complaints and general enquiries concerning the distribution network, installation inspection and emergency response to installation and network safety issues. • Network control – cost of monitoring and controlling of Ausgrid's infrastructure. It also includes emergency and incident management. • Engineering, planning and connections - costs of operational engineering and planning activities related to the support of the Ausgrid network and costs incurred in considering network planning implications dealing with commercial customers contemplating large scale potential connections to the Ausgrid network. d) ***Training and development*** – costs relating to centralised coordination and delivery of the technical, regulatory and professional development needs for Ausgrid's employees and compulsory training related to network access for contractors who work on the network. This also includes the four technical development programs: Apprentices, Engineering Officer Traineeships, Electrical Engineering Cadetships and the Engineering Graduate. e) ***Finance*** – cost relating to: • Corporate accounting and performance reporting. • Budgeting, forecasting, commercial services and business support. • Treasury, taxation and cash management. • Fixed asset management and reporting. f) ***Other operations and business support costs*** – These relate to: • Regulation and compliance management. • Corporate governance. • Contact centre and data operations. • Fleet and logistics management. • Insurance. • Human resources management. Workers compensation, occupational health, well being and safety. Management, regulation and management of non network alternative programs.
Other – achieve opex objective 1.	Ausgrid's other opex relates to demand management. This expenditure is required to manage the demand on our network through various non network alternatives.

In addition to the forecast opex that Ausgrid proposed, the AER also allows a debt raising cost. The AER has accepted this cost as a legitimate operating expenditure that is required to meet the opex objectives.

Satisfying the opex criteria with regard to the opex factors

Our initial proposal was accompanied by expert economic opinion from NERA Consulting on the correct economic interpretation and approach to the opex criteria in the rules, and on how to demonstrate that the forecast opex reflected these criteria with regard to the factors.[210]

A key element of NERA's advice was that there is no external, observable measure that can be relied upon to demonstrate and/or conclude that the total forecast expenditure is efficient. In this context, NERA considered that a practical demonstration that the forecast expenditure reasonably reflects the expenditure criteria can be achieved by:

- Demonstrating that the process the DNSP employed in developing its forecast expenditure is efficient and prudent.
- Using indicators to assess the reasonableness of the result and to inform a decision on whether the resulting forecast expenditure (from applying a prudent forecasting approach) reasonably reflects the efficient cost.

We showed that NERA's practical approach reflect the opex factors that the AER must consider in deciding whether it is satisfied that the forecast expenditure reasonably reflects the expenditure criteria.

Methodology employed by Ausgrid to derive forecast opex

In our initial proposal we demonstrated that we have a fit for purpose' approach to forecasting our operating expenditure for the 2014-19 period.

Our initial step in developing our forecast opex for 2014-19 was to disaggregate our actual costs in 2012-13 (most recent known costs) into various cost categories. These cost categories represented the costs of undertaking a set of related activities to provide standard control services and to achieve the opex objectives (for example, maintenance opex, system control, finance, human resources, information technology etc.).

When undertaking this assessment we considered whether there were any costs in the 2012-13 year that were non-recurring, such as one-off actuarial adjustments. It also involved considering whether the 2012-13 base year represented an efficient starting point for forecasting opex. As we note in the following section, we considered that our performance against the target efficient allowance set by the AER in 2009-14 provided demonstration that the starting point was efficient. This is consistent with the EBSS applied by the AER to incentive us to improve efficiency in this period.

We next assessed each cost category to determine whether the forecast opex requirement in the 2014-19 would be different to our actual costs in 2012-13. This required consideration of the change factors that may influence the efficient costs of providing each opex activity. This included legislative changes, known compliance issues with our existing standards, and changes to our operating environment.

Our forecasting approach also explicitly considered the efficiencies we could achieve in the 2014-19 period. This recognised that a prudent business is continually seeking to implement improvements in businessimprovements in business practices as and when opportunities arise. Our forecast considered the level of improvements we could achieve in our circumstances based on a granular assessment of the activities we perform. We also recognised that the benefits of certain efficiency programs have offsetting increases in costs via implementation in the forthcoming period.

We sought to show that the resultant approach was 'fit for purpose' in that it ensured that the nature of each cost category and its relevant underlying drivers are appropriately accounted for such that the resulting forecast opex is reflective of the efficient costs that a prudent operator would require to achieve the opex objectives. This process gave us confidence that our total forecast opex would reasonably reflect the opex criteria and ensures that the National Electricity Objectives and the Revenue and Pricing Principles are met, especially that we are afforded a reasonable opportunity to recover at least the efficient cost we expect to incur in the 2014-19 period.

Our initial proposal also identified the relevant opex factors that align to assessing the prudency of forecasting approach, these were:

- Substitution possibilities between operating and capital expenditure (expenditure factor 7). Our forecasting process considered the consequential impact of efficient capital investment on our future opex requirements.
- The extent to which Ausgrid has considered and made provision for efficient non network alternatives – We considered the extent to which demand management activities taken to defer capex would impact on opex in the 2014-19 period.
- Relative prices of capital and operating inputs (expenditure factor 6).
- The extent to which the expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the DNSP in the course of its engagement with electricity customers (expenditure factor 5A).

[210] Refer to Ausgrid initial proposal Attachment 5.31.

Indicators to assess whether process results in efficient cost

NERA's advice suggested there are partial indicators and other factors that would assist in confirming the efficient level of the forecast expenditure that was derived from a prudent approach. These factors are stated in the rules and are intended to assist the AER in making a decision on whether the total forecast expenditure reasonably reflects the expenditure criteria. Accordingly, our initial proposal addressed these factors to satisfy the AER that our forecast opex meets the criteria.

Opex factor 5 states that the AER must have regard to the actual and expected opex of the DNSP during any preceding regulatory control period. We demonstrated that our proposal was grounded on our efficient performance in the past, and that this had formed an important element of our regulatory proposal. We showed that we performed better than the targets that the AER had determined were efficient, as can be seen in Table 30. This was also illustrated by our performance against the EBSS target set by the AER.

This performance was achieved by the implementation of a number of cost saving initiatives in the 2009-14 period. These initiatives are consistent with the regulatory framework which encourages and provide incentives for the business to improve cost efficiencies.

It has set a solid platform for Ausgrid in ensuring that the forecast opex for the 2014-19 period reasonably reflects the efficient costs that a prudent operator would need to achieve the opex objectives, taking into account a realistic expectation of demand forecasts and cost inputs.

Opex factor 4 requires that the AER must consider the most recent annual benchmarking report that has been published under rule 6.27 and the benchmark capital / operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period. The purpose of this factor is for the AER to consider whether available benchmarking information can provide a partial indicator of the efficiency of the forecast expenditure, and if so the investigations and weight that should be ascribed to that data. The AER was due to publish its first benchmarking report in September 2014, and therefore we were not provided in a position to make representations on this report at the time of submitting our initial regulatory proposal.

However we did address benchmarking in our initial proposal. In this regard, we submitted a comprehensive report on the limitations and role of benchmarking as a partial indicator (Attachment 5.33 of Ausgrid's initial proposal). Our analysis identified that benchmarking has inherent limitations such as inability to conduct 'like for like' analysis across peer firms, data inconsistency and inaccuracy, and failure to meet statistic principles. We noted that appropriate benchmarking does have a role in guiding the regulator to areas requiring further granular analysis. Importantly, it should not be used to reject a DNSP's proposal, or as a basis to substitute the forecast given the inherent limitations as a tool and given that it is only one of 12 different factors that the AER must have regard to.

We placed limited weight on benchmarking analysis as a valid test of the efficiency of our forecast. This was due to our assessment of tools that the AER was developing which we considered did not meet criteria for an effective benchmark as developed by the Productivity Commission. We complemented our analysis by providing a report by Huegin Consulting which provided a factual demonstration of the limitations and shortcomings of benchmarking analysis.

In any case as outlined below, factor 4 (benchmarking) is only one of the factors the AER need to consider and is not intended to be the sole or dominant factor.

Finally we showed that opex factor 9, which is the extent to which forecast expenditure is referable to arrangements with other persons that do not reflect arm's length transactions, is not applicable to our circumstances, and is therefore is not a valid check on our forecasting process.

Summary

Ausgrid has approached the task required under the rules with careful consideration and analysis to ensure that the forecast opex we proposed reasonably reflects the opex criteria, taking into account the opex factors. This opex represents an appropriate balance between price, safety and reliability and this is in accordance with the rules.

6.4 AER's decision

In its draft determination, the AER made a constituent decision to reject our proposed opex of $2,842.9 million ($2013/14), and substitute an amount of $1,721.9 million ($2013/14 for the 2014-19 regulatory control period, a 39.4% reduction. The AER considered its alternative estimate of Ausgrid's forecast opex reasonably reflects the opex criteria.

We do not accept the AER's draft decision on forecast opex and have grave concerns about the process the AER undertook and the merits of its decisions and the reasons and analysis supporting this decision. In the sections below, we address the AER's decisions and our interpretation of reasons for them. We also demonstrate why we have not sought to revise our proposal to incorporate the AER's draft decision on opex and reasons for it.

AER's approach and methodology for assessing our proposal

In section 7.3 of Attachment 7 to its draft decision, the AER sets out its assessment approach and the methodology it used in this assessment. The AER stated that:[211]

> *We decide whether or not to accept the service provider's total forecast opex. We accept the service provider's forecast if we are satisfied that it reasonably reflects the opex criteria. If we are not satisfied, we replace it with a total forecast of opex that we are satisfied does reasonably reflect the opex criteria.*

The AER also stated that in making the above decision, it also has regard to the opex factors. The AER stated that it attached different weight to different factors when making its decision to best achieve the NEO and cited the following AEMC's statement in support of this:

> *As mandatory consideration, the AER has an obligation to take the capex and opex factors into account, but this does not mean that every factor 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.*** *(emphasis added)*

As noted in Chapter 1, the 2012 rule change inserted an additional opex factor in the form of clause 6.5.6(e)(12). This clause allows for the AER to consider any other factor and which the AER has notified Ausgrid in writing prior to the submission of Ausgrid's revised proposal.

The AER's draft decision considered that the AER's benchmarking data set and the benchmarking techniques it used are also relevant opex factors under clause 6.5.6(e)(12).

Having outlined the requirements of the rules in relation to the tasks that it has to undertake in assessing Ausgrid's forecast opex, the AER then outlined its approach to these tasks; that is, determining whether Ausgrid's proposed forecast opex reasonably reflect the opex criteria having regard to the opex factors. The AER outlined its approach to the task as follow:

> *Our approach is to compare the service provider's total forecast opex with an alternative estimate that we develop ourselves.By doing this we form a view on whether we are satisfied that the service provider's proposed total forecast opex reasonably reflects the criteria. If we conclude the proposal does not reasonably reflect the opex criteria, we use our estimate as a substitute forecast.*
>
> *Our estimate is unlikely to exactly match the service provider's forecast because the service provider may not adopt the same forecasting method. However, if the service provider's inputs and assumptions are reasonable, its method should produce a forecast consistent with our estimate.*
>
> *If a service provider's total forecast opex is materially different to our estimate and there is no satisfactory explanation for this difference, we may form the view that the service provider's forecast does not reasonably reflect the opex criteria. Conversely, if our estimate demonstrates that the service provider's forecast reasonably reflects the expenditure criteria, we will accept the forecast. Whether or not we accept a service provider's forecast, we will provide the reasons for our decision.*

How the AER developed its alternative forecast

The AER's approach to forming an alternative estimate of opex was based on five steps. The AER explained this as follows:[212]

> *We typically use the service provider's actual opex in a single year as the starting point for our assessment. While categories of opex can vary from year to year, total opex is relatively recurrent.*
>
> *We assess whether opex in that base year reasonably reflects the opex criteria. We now have a number of different techniques including economic benchmarking, by which can test the efficiency of opex in the base year. If necessary, we make an adjustment to the base year expenditure to ensure that it reflects the opex criteria. We can utilise the same techniques available to assess the efficiency of base year opex to make an adjustment to base year opex.*
>
> *As the opex of an efficient service provider tends to change over time due to price changes, output and productivity, we trend the adjusted base year expenditure forward over the regulatory control period to take account of those changes. We refer to this as the rate of change.*
>
> *We then adjust the base year expenditure to account for any other forecast cost changes over the regulatory control period that would meet the opex criteria. This may be due to new regulatory obligations and efficient capex/opex trade-offs. We call these step changes.*
>
> *Finally we add any additional opex components which have not been forecast using this approach. For instance, we forecast debt raising costs based on the costs incurred by a benchmark efficient service provider. If we removed a category of opex*

[211] AER draft decision - Attachment 7, p. 7-9

[212] AER draft decision - Attachment 7, p. 7-13.

from the selected base year, we will need to consider what additional opex is needed for this category of opex in forecasting total opex.

The AER noted that underlying its approach are two general assumptions: the first being that the efficiency criterion and the prudence criterion in the NER are complementary, and the second being that actual expenditure was sufficient to achieve the expenditure objectives in the past.

The AER's decision to reject proposed expenditure

The AER's decision clearly reflects its approach to use its alternative forecast as the reference point for assessing whether our proposed forecast opex satisfied the opex criteria. The AER stated:[213]

> *We are not satisfied that Ausgrid's total forecast opex reasonably reflects the opex criteria. **We compared Ausgrid's opex forecast to an opex forecast we constructed using the method outlined above**. Our estimate is of the efficient opex a prudent operator would require to achieve the opex objectives. **Ausgrid's proposal is higher than ours and we are satisfied that it does not reasonably reflect the opex criteria. For this reason, we have substituted Ausgrid's total opex forecast with our total opex forecast.** (emphasis added)*

The AER's findings were based on the steps of its review set out in its assessment method. The AER was not satisfied that our actual costs in the 2012-13 base year were efficient. The AER were also not satisfied that the rate of change it implied from our proposal met the opex criteria. Finally the AER identified any other costs that it considered was a proposed step change, and considered that these did meet the opex criteria. Table 32 summarised the AER's findings on Ausgrid' proposed forecast using its approach.

Table 32 – Summary of AER's findings on Ausgrid's forecast opex

Components of the AER's 'base-step-trend' method	AER's findings on Ausgrid's forecast opex
Base year	Rejected Ausgrid base year amount based on economic benchmarking, partial performance indicator benchmarking and category analysis benchmarking. The AER also claimed that it has considered our regulatory proposal and submission to the issue paper. The AER claimed that our regulatory proposal and subsequent submission is 'evidence that Ausgrid has historically had some inefficient practices. The AER also cited the CEO's comments. Finally the AER referred to its consultant report (Deloitte Access Economics) which found that Ausgrid's labour and workforce management issues meant the base year would not likely represent efficient costs.
Rate of change	The AER found that in cumulative terms there is no significant difference between the AER's own calculation of rate of change and that of Ausgrid. The AER attributed the reasons for the difference as: • Difference in the labour price forecast used by Ausgrid and the AER. • Difference in forecast output change; the AER classified Ausgrid's change factors as network size, customers or output. On the other hand, the AER considers that its outputs of ratched maximum demand, customer numbers and circuit length are better measures. • Difference in productivity change – Ausgrid's productivity change includes savings and implementation costs.
Step change	The AER rejected cost increase above Ausgrid's base year costs except for the increase associated with the leaseback cost of head office building. The AER rejected: • Cost increase due to the loss of synergy and the impact of compliance with the AER's approved cost allocation method on the basis that an efficient base level of opex already account for the efficient opex needed. • Compliance with obligations (private pole inspection and asbestos) – The AER considered these do not relate to new obligations and hence the base level of opex would provide for these costs already. • The AER considered redundancy cost is not a cost needed by a benchmark efficient service provider. • Investment in broad based demand management to reduce network capex. The AER determined that the introduction of cost reflective pricing would deliver sufficient price signals such that customer response would defer localised constraints.

AER's Substitute allowance

Having relied heavily on benchmarking to reject our forecast opex, particularly our base year costs and the incremental costs, the AER then relied on the same benchmarking analysis as a basis to substitute for its own forecast opex. The AER's substituted Ausgrid's forecast opex of $2,842.9 million with $1,721.9 million.

[213] AER draft decision - Attachment 7, p. 7-13.

Firstly, the AER adjusted Ausgrid's base year opex using its benchmarking result with the following adjustments:

- 10 % allowance for those operating environment not capture in its preferred benchmarking technique.
- Compared Ausgrid's efficiency score to a weighted average of all networks with efficiency score above 0.75 rather than the most efficient provider in its preferred model.

The AER concluded that:

> *We estimate a benchmark efficient service provider would need less base opex than a forecast based on Ausgrid's opex in 2012-13.* [214]

The AER's adjusted base year opex, based on its preferred benchmarking technique, resulted in a starting opex of $325.9 million, a reduction of 33.3% from Ausgrid's base year of $488.6 million (adjusted by the AER)[215].

Secondly, the AER applied its calculation of the rate of change to the substitute base year to derive an opex forecast for each year of the 2014-19 period.

Finally the AER considered that only the incremental costs associated with the leaseback of Ausgrid's head office building should be allowed. The AER also applied debt raising cost of $39.4 million (nominal).[216]

AER's assessment under the rules

The AER stated that in deciding whether or not it was satisfied the service provider's forecast reasonably reflects the opex criteria it had regard to the opex factors. This is set out in Table 7.7 of the AER's draft decision. The AER considered that 2 of the 9 factors identified in the rules were not relevant. The AER also decided to develop 2 of its own factors both of which relate to benchmarking.

When making its assessment against the opex factors, the AER has sought to demonstrate how its assessment method relates to one or more opex factors. In particular, the AER has sought to show how its alternative estimate of opex, including the benchmarking analysis it uses to derive an estimate of the base year, meet the factors. For instance:

- Of the 7 of the 9 relevant factors, the AER refer in some part to its benchmarking analysis.
- When assessing the relative prices of capital and operating expenditure the AER noted that its rate of change adjustment of base year opex captures the estimate of the inputs that Ausgrid is likely to face in the forecast period. The AER stated that this ensures its estimate includes adequate compensation for efficient changes in inputs over time. It also notes that it had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. It stated that multilateral total factor productivity analysis considered the overall efficiency of networks with in the use of both capital and operating inputs with respect to the prices of capital and operating inputs.

6.5 Issues with the AER's assessment approach

We have reviewed the AER's draft decision on opex with a mind to considering whether any revisions are required to incorporate the substance of any changes required by the AER or reasons for it.

In reviewing the decision, we have formed a view that the AER has fundamentally misconstrued its task under 6.5.6 of the rules. We have identified the three areas in which the AER has misdirected itself:

- The AER did not apply itself to the opex criteria to critically assess how our proposals failed to meet them. In doing so, the AER has not engaged with our specific circumstances and proposed reasons underlying our opex, in a way that enables a proper assessment under the rules. Further we contend that that AER's alternative forecast is not capable of accounting for our circumstances, and does not properly account for the range of costs that may satisfy the opex criteria and factors.
- Placing undue weight on benchmarking analysis - The AER has placed unreasonable weight on benchmarking analysis in rejecting and substituting our proposed opex, particularly in circumstances where the benchmarking analysis that has been done is such that it cannot be reasonably relied on. This is clear from the AER's stated techniques, and the manner in which it has sought to address the opex factors. Further, we demonstrate that it is unreasonable to place weight on the benchmarking analysis when making its decision due to the errors and limitations inherent in its development and application.
- AER did not consider risks to safety and reliability from substitute opex - The AER's method for deriving a substitute allowance relies on a benchmarking model that is entirely divorced from the method and cost categories inherent in our forecast opex. In doing so the AER has considered that its task is to set an overall allowance without undertaking a line by line assessment. We consider this is unreasonable. The AER should have undertaken a proper risk assessment of the substitute allowance to satisfy itself of the implications for additional risk for our business that had not been considered. This is outlined in section 6.4.3.

[214] AER draft decision, p. 7-19

[215] For debt raising costs, CAM and service classification. See further in Table 33.

[216] AER draft decision - Attachment 3, p. 3-842.

The above concerns are further detailed below. Further to these, we also have concerns about the merits of the AER's benchmarking results and the RIN data upon which these results are based. We outline these concerns further below.

We consider that if the AER had undertaken its task in accordance with the rules, then it would have been satisfied that our proposed opex satisfies the opex criteria. For this reason, we have seen no reason to revise our proposal to address the issue raised by the AER's assessment approach.

Before turning to these matters, as we have noted above, the AER's assessment method stemmed from a misconception of its powers following amendments to the rules and NEL in 2012 and/or the substantive effect of this rule change. We consider:

- The AER incorrectly stated that its determination is premised on an overall revenue allowance, as opposed to its individual constituent decisions.
- The rule change does not obviate the need for the AER to consider the individual circumstances of Ausgrid in the forthcoming regulatory period, something we considered the AER failed to do; and
- The rule change does not allow the AER to mandate or use a particular forecasting method as the sole method for determining an efficient and prudent forecast opex.

'Overall revenue allowance'

The AER stated that:

> *These legislative changes have made this decision different from our previous decisions. In particular, for the first time, we have specifically assessed our overall revenue decision and its contribution to the achievement of the NEO. We consider this is an appropriate change as we determine an overall revenue allowance. We do not seek to interfere in the decisions a service provider will make about how and when to spend the total capex or opex allowance to run its network. The service provider is free to choose how to manage its allowance. For example, we do not approve individual capital expenditure projects that a distributor must then implement. Rather, we determine the sum total of revenue that we consider satisfies the requirements of the NEL and NER.*[217]

We consider that such analysis has infiltrated the AER's assessment of opex, where it has sought to develop a revenue allowance that in its mind achieves the NEO. This is seen in section 5 of its overview where the AER summarises the key underlying drivers for its decision and indicate their impact on the constituent components of its decision. It then examines the cumulative effect of drivers on the efficient level of revenue.

The AER's task is to assess our forecast opex under the criteria rather than to derive an efficient level of revenue overall and, in circumstances where it is not satisfied that the forecast opex amount reasonably reflect the operating expenditure criteria, determine a substitute amount that the AER is satisfied reasonably reflects the operating expenditure criteria. This is plain from clause 6.12.1 of the rules. In approaching the forecast operating expenditure allowance for the 2014-19 period, the AER seems to have misunderstood this requirement. The distribution determination is built on each of the constitutent decisions the AER is required to make pusuant to clause 6.12.1, and the correct application of the rules in making each of those decisions will provide a revenue stream that meets the NEO. While it should undertake a cross check of its overall decisions, this is in the context of ensuring that it has taken into account relevant inter-relationships.

Forecasting methods

The AER stated that:

> *In assessing Ausgrid's forecasting method we sought to identify if and where Ausgrid's forecasting method departed from our guideline forecasting method. Where Ausgrid's forecasting method did depart from our guideline forecasting method we considered whether this departure explains the difference between Ausgrid's forecast of total opex and our own.* [218]

We are very concerned with the AER's implication that we are required to use its forecasting method. There is no such obligation imposed on us by the NER.

The AER seems to have misunderstood the powers in relation to the AEMC's rule change in 2012 on the approach to be taken assessing expenditure forecasts. The AER convey that the AEMC authorised an approach where the AER use its own alternative forecast as a reference point, and accept that proposal only if the DNSP can satisfactorily explain for the differences.

The AEMC's statements do not suggest that the AER have the power to simply adopt its own forecasting estimate as the sole reference point for determining an efficient forecast of opex. The AEMC stated:

> *The NSP's proposal is necessarily the starting point for the AER to determine a capital expenditure or operating expenditure allowance, as the NSP has the most experience in how its network should be run. Under the NER the AER is not "at large" in*

[217] AER draft decsion, Overview, p. 16.

[218] AER draft decsion - Attachment 7, p. 7-171

being able to reject the NSP's proposal and replace it with its own since it must accept a reasonable proposal. But the AER should determine what is reasonable based on all of the material and submissions before it.

As can be seen in Table 33 below, the AER's draft decision effectively imposed its own forecasting method or alternatively used this method in lieu of a proper assessment of our proposed forecast opex based on the opex criteria, opex factors and Ausgrid's individual circumstances. The AER's method for assessing a DNSP's proposal and determine a substitute forecast opex is based on the following formula:

$$Opex_t = \prod_{i=1}^{t}(1 + rate\ of\ change_i) \times \left(A_f^* - efficiency\ adjustment\right) \pm step\ changes_t$$

As noted above, in the 2012 rule change, the AER proposed to the AEMC that it be allowed to dictate a forecasting method. This was rejected by the AEMC in the final rule determination. The AEMC stated:[219]

The Commission accepts that responsibility for developing a NSP's proposal should remain with the NSP. This includes the development of an expenditure forecast in a manner that the NSP views as appropriate. It is the AER's role to assess the NSP's proposal using any tools it views as appropriate… As a result, the final rule requires the AER to develop guidelines on its assessment techniques. At the framework and approach stage the AER will determine how the guidelines apply to the particular NSP. The NSP is then required to submit information in compliance with the application of the guidelines as determined in the framework and approach paper with its proposal. This information would not form part of the NSP's formal proposal and therefore should not need to be subject to the same sign-off requirements as the proposal. ***There will no longer be a requirement to include in the proposal itself a forecast determined in a manner set by the AER.*** *However, the final rule does not preclude the NSP from including information in its proposal if it so chooses.*

We note that we submitted to the AER in November 2013 a 'forecasting methodology statement' required by clause 6.8.1A of the rules. This requirement was the result of the 2012 rule change and the purpose of which is to provide a 'starting point' in the early engagement between Ausgrid and the AER on the forecasting methodology Ausgrid proposes to use; so as to assist the AER in its assessment of the Ausgrid's proposed forecast operating expenditure and capital expenditure.[220] We adopted the methodologies outlined in this statement for the transitional regulatory proposal and initial regulatory proposal.

Since the submission of the statement and the regulatory proposals and until the publication of the AER's draft decision, we have no indication from the AER as to any concerns that it may have on our proposed forecasting method or any engagement from the AER on the proposed method. The AER appears to have simply dismissed our methodology in the draft decision. We address this further below.

Role of benchmarking

In addition, the forecasting method that the AER relied on to reject our forecast opex and determine a substitute relied heavily on its benchmarking results. The AER is also of the view that the changes to the NER placed significant new emphasis on benchmarking. The AER stated:

While these general steps are consistent with our past determinations, we have adopted a significant change in how we give effect to this approach, following the major changes to the NER made in November 2012. Those changes placed significant new emphasis on the use of benchmarking in our expenditure analysis. We will now issue benchmarking reports annually and have regard to those reports. These benchmarking reports provide us with one of a number of inputs for determining the benchmark efficient costs of providing opex.

The AER has placed almost exclusive weight on its benchmarking analysis and applied it deterministically to both reject our forecast opex without proper assessment and to substitute for its own forecast opex amount. This is evidenced by the tables below which shows how the AER had applied its benchmarking result to determine a substitute forecast opex, after having rejected our forecast by comparing the result from this analysis with our proposed forecast.

1. Benchmarking → 2. AER's base year opex adjustment based on benchmarking → 3. AER's opex forecast

[219] AEMC 2012, Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Rule Determination, 29 November 2012, p. 109.

[220] AEMC 2012, Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Final Position Paper, 29 November 2012, Sydney, p. 110.

Table 33 – Role of benchmarking in forecast opex ($ million, 2013/14)

Step	Value	Calculation description / source (all $000)
Step 1: Benchmarking & AER's calculations on benchmarking output[221]		
Determine Ausgrid's score from benchmarking	44.7%	Analysis by Economic Insights using Cobb-Douglas SFA model applied across 7 years of historic data
Determine efficiency frontier to use	86.2%	Customer numbers—weighted average of top 5 scores (from EI analysis above)
Calculate new efficiency target downwards by 10% 'margin allowance' to account for differences	78.4%	= efficiency target / 1 + margin allowance = 0.862/1.1 = 78.4%
Calculate implied opex reduction to reach efficiency target (i.e. gap to the efficient frontier)	**-43%**	= 1- (Ausgrid eff score / target) = 1-(44.7/78.4) = 43%
Step 2: Construct theoretical 'substitute base year' opex[222]		
Calculate average of 8 years of opex from 2006 – 2013 (inclusive)	$509.27m	= average ('opex quantity') from RIN data, where 'opex quantity' is past years' opex in $FY13 = 509,271
Calculate the implied opex reduction to move to a theoretical efficient level	-$218.95m	= 509,271 * **0.43 [from step 1 above)** = 218,945
Reduce this by the implied opex reduction to make it 'efficient average opex'	$290.31m	= average ('opex quantity') – implied opex reduction = 509,271 - 218,980 = 290,310
Escalate average opex to create an efficient 2012/13 opex to account for output growth during the 2006-2013 period ('substitute base opex' in spreadsheet)	$314.93m	= average efficient opex * composite growth factor[223] = 290,310*(1+0.0849)
Express 'substitute base opex' in 2013/14 dollars	**$325.87**	= 314,928 * CPI index = 314,928 * 1.035 = 325,866
Step 3: Construct theoretical 'efficiency adjustment[224]		
Adjust Ausgrid's reported base year opex (2012/13) to allow comparison (adjust for CAM & service classification changes and remove DRC)	$472.18m	= total opex – debt raising costs + CAM adjustment uplift – costs related to service classification change = 503.58m – 0.36m + 3.71m – 34.75m = 472.18m
Express Ausgrid's adjusted base opex in 2013/14 dollars	$488.57m	= 472.18m * CPI index = 472.18m * 1.035 = 488.57m
Calculate the difference between the 'substitute base opex' and Ausgrid's adjusted base year opex (in 2013/14 dollars)	$162.71m	= Ausgrid's adjusted base opex - substitute base opex = 488.57m – **325.87m (from step 2 above)**
Express as a percentage **'efficiency adjustment'**	**33.3%**	= 162.71/488.57 =0.333

[221] 'AER draft decision Ausgrid distribution - Opex base year adjustment draft decision - November 2014.xls'

[222] 'AER draft decision Ausgrid distribution - Opex base year adjustment draft decision - November 2014.xls'

[223] This incorporates output growth base on customer numbers, circuit length, ratcheted maximum demand and a small factor for the amount of underground network

[224] 'AER draft decision - Ausgrid distribution - Opex base year adjustment draft decision - November 2014.xls'

Step 4: Applying the theoretical 'efficiency adjustment' - The AER's calculation of opex base year and forecast for subsequent years, using equations in Expenditure Assessment Guideline[225]		
Applies the AER's forecast 'base, step, trend' opex forecasting formula: $$Opex_t = \prod_{i=1}^{t}(1 + rate\ of\ change_i) \times (A_f^* - efficiency\ adjustment) \pm step\ changes_t$$ *Where A_f*= the estimated actual opex in the final year of the preceding regulatory control period*		
Calculate, estimated final year opex *, A_f*=* $F_f - (F_b - A_b) + non\text{-}recurrent\ efficiency\ gain_b$ F_f is opex allowance for the final year (2013/14) F_b is opex allowance for base year (2012/13) A_b is the actual opex in base year (2012/13)	$521.62m	12/13 actual opex – DRC costs = 503.22m ($12/13) ***$A_b$,*** 12/13 actual opex – DRC costs = 520.7m ($13/14) ***$F_b$,*** Opex allowance for 12/13 = 612.73m ($13/14) ***$F_f$*** , Opex allowance for 13/14 = 613.66m ($13/14) Non-rec. eff. gain = 0 **A_f*** = 613.66 – (612.73 – 520.7) = 521.62m
Adjust A_f* (final year opex) for CAM & service classification changes	$489.46m	A_f* - CAM adj uplift – costs related to service classification change = 521.62m + 3.8m – 35.96m = 489.46m
Calculate the opex reduction using the '***efficiency adjustment'*** from benchmarking	-$163.02m	Opex adjustment = final year opex * efficiency adjustment = 489.46m * **0.33 (from step 3 above)** = 163.02m
Calculate efficiency adjusted final year opex – a theoretical efficient opex in 2013/14	**$326.48m**	Theoretically efficient final year opex = Actual final year opex - 163.02m = 326.48m
Calculate opex forecast by applying growth and allowed step changes: $$\prod_{i=1}^{t}(1 + rate\ of\ change_i) \times (A_f^* - efficiency\ adjustment) \pm step\ changes_t$$ ***Year 1*** (14/15) = (326.5*(1+0.022)*(1*1.018)+7 = **$337.5m** (see other years in Table 34)		

Note: Numbers may not add due to rounding.

[225] 'AER draft decision Ausgrid distribution determination - Ausgrid 2014 - Opex model - November 2014.xls'

Table 34 – Forecast opex for 2014-19 based on 'benchmarked' base year ($ million, 2013/14)

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	Comment
Benchmark adjusted final year opex, Af*	326.5 (from step 4 above)						
Rate of change: AER output growth forecast		2.2	2.5	2.8	3.0	2.9	Based on only 3 cost drivers with weightings derived from historic average trends
Rate of change: AER price growth forecast		1.8	1.8	2.9	3.4	3.1	Average of Independent Economics and Deloitte Access Economics forecasts
Escalated Af*		330.5	334.8	340.5	346.9	353.0	
Step change: HOB lease		7.0	7.4	9.3	-3.7	-3.7	Added in after escalation
AER's SCS opex forecast		**337.5**	**342.2**	**349.8**	**343.2**	**349.2**	

Note: Numbers may not add due to rounding.

We consider that the AER has misconceived the AEMC's intent on the role of benchmarking. The AEMC did agree that benchmarking is a valid exercise in assessing the efficiency of a NSP's capex and opex forecasts it nevertheless did not consider that it should be of greater priority or emphasis than any other opex factor:

> *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.*

In addition to the serious concerns with have with the deterministic way the AER has applied its benchmarking results, we also have concerns with the merits of the AER's benchmarking results (for example the selection of the frontier, the quality of the RIN data used). We address these below.

AER's alternative estimate

The AER's decision makes clear that it has given primacy to its own alternative estimate for opex, rather than start with Ausgrid's proposal. This is clear from the following statement in its decision, which shows that the AER's starting point is its own 'alternative forecast', and that its test of our proposal against the criteria is whether we can satisfactory explain any difference.

> *Our approach is to compare the service provider's total forecast opex with an alternative estimate that we develop ourselves. By doing this we form a view on whether we are satisfied that the service provider's proposed total forecast opex reasonably reflects the criteria. If we conclude the proposal does not reasonably reflect the opex criteria, we use our estimate as a substitute forecast.*
>
> *....Our estimate is unlikely to exactly match the service provider's forecast because the service provider may not adopt the same forecasting method. However, if the service provider's inputs and assumptions are reasonable, its method should produce a forecast consistent with our estimate.*
>
> *If a service provider's total forecast opex is materially different to our estimate and there is no satisfactory explanation for this difference, we may form the view that the service provider's forecast does not reasonably reflect the opex criteria.*
>
> *We have used this general approach in our past decisions. It is a well- regarded top down forecasting model.*[226]

We consider that in applying such an approach the AER has misconstrued its task under the rules. As we outline below, the AER's task is to review a DNSP's proposal in light of the opex criteria.

Issues with way AER applied alternative estimate to reject forecasts

The AER is correct in asserting that the AEMC's rule change did clarify that the rules do not limit the assessment tools that it can use to assess our proposal. The development of an alternative estimate of opex is not prohibited by the rules, and is expressly identified by the AEMC as a tool the AER can use.

[226] AER draft decision, page 7-13.

However in this case, we are concerned that the AER has gone outside of its powers by using the alternative estimate as a 'threshold' that our proposal must pass to satisfy the rules. In this respect, the AER has presumed that the alternative estimate is correct unless a DNSP can provide satisfactory evidence to show why its proposal differs.

The AEMC's rule change in 2012 was unequivocal that our proposal was the starting point of the AER's assessment:

> *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.*

In contrast, the AER's alternative estimate is at best a 'rough guide', without any knowledge or foresight of our circumstances and drivers of expenditure. Indeed if the task were as simple as to develop an alternative estimate, the rules would simply require a DNSP to explain any increases or decreases relative to the AER's formula (or to use the formulae itself). As we have noted above, the AEMC rejected in its final rule determination the AER's proposal to allow it to specify the models and /or methods that a NSP must apply to develop expenditure forecasts.

We therefore consider it unreasonable for the AER to form a view that its alternative estimate is more accurate than our proposal. Further the manner in which the AER has constructed the estimate, does not enable to it fully capture costs that may in fact satisfy the opex criteria had a full assessment been undertaken of our proposal. For example:

- The AER's test of an acceptable 'step change' to be included in its alternative forecast is overly narrow, and effectively precludes opex that meets the criteria, with regard to the factors. For example, the AER has disallowed increases in private mains inspections and asbestos costs on the basis that there are no new regulatory obligations, and therefore the expenditure is discretionary. This has ignored information which clearly shows that Ausgrid requires the additional expenditure to address increasing risks associated with an existing regulatory obligation. The AER's method simply assumes that costs in the base year reflect the amount required to achieve the opex objectives, and does not consider whether additional expenditure may be required to address changing and increasing risks associated with the need to comply with an existing obligation.
- The AER's output growth factor cannot account for the changes in relation to Ausgrid's changing circumstances going forward; for example, the cost impact of losing the synergy from being an integrated business. The AER's output growth factor therefore cannot reasonably reflects a realistic expectation of demand forecast and costs inputs; an opex criteria that the AER must consider.

Additionally, the AER's alternative forecast opex is based on a top-down approach that does not take into consideration the underlying drivers and programs required to meet the NEO nor does it adequately account for the outcomes in terms of network safety and reliability.

Did not sufficiently engage with our proposal

In testing why our proposal does not meet its alternative estimate, the AER has not undertaken a sufficient examination of our proposal. Rather the AER has simply assumed that its estimate is correct, and undertaken a superficial review of elements of our proposal. We consider that the AER's narrow review of the substantive material we provided in our proposal has not allowed it to make a decision on whether our proposed opex satisfies the criteria.

Attachment 7 of the AER's decision stated that it examined our regulatory proposal and supporting information. However, this is not evident in the AER's reasoning. Of the 7 assessment techniques used by the AER to assess the efficiency of our 2012-13 actual (base year) costs, 5 relate to benchmarking. [227]

In not examining our proposal, the AER has failed to consider the drivers and circumstances underlying our opex requirements for the forthcoming regulatory period. For instance, the AER has:

- Not referred to the extensive attachments we provided which shows how our total forecast opex achieves the opex objectives and satisfies the opex criteria.
- Not undertaken an assessment of the activities we perform in achieving the opex objectives, and the costs entailed in doing so. Had the AER undertaken this assessment it would have been in a better position to understand the need and efficiency of our operations in our network and circumstances. For instance, it would have understood that there are safety and reliability consequences from not undertaking maintenance activities.
- Ignored the materials we provided to show that we had responded to the incentives in the framework by performing better than the prudent and efficient allowance set by the AER in the 2009-14 determination. In this respect, we provided compelling information to the AER to demonstrate that our performance was significantly better than the allowance set by the AER as a result of efficient management practices and successful implementation of efficiency programs. The AER should have taken this into account when assessing our proposal. In effect the AER has ignored the validity of its own determination in 2009-14, and in doing so, has rejected the incentive framework that lies at the heart of economic regulation.

[227] See Table 7.3 of the AER draft decision, p. 7-18 and p. 7-19.

- Did not assess change factors unique to our network and circumstances that would impact our cost structure in the 2014-19 period. For instance, the AER did not undertake a review of the loss of synergy costs, something that the AER accepted in the 2009-14 determination for Ausgrid as a pass through event.
- Ignored information we provided on the efficiencies we forecast to derive in the 2014-19 period, which showed that our forecasting processes had incorporated a level of efficiency that was achievable in our circumstances.

Reliance on benchmarking as sole criteria

It is clear from the AER's decision that benchmarking has been the primary evidence underlying the AER's rejection and substitution of our proposed opex. The AER's substitute base year has been derived from a benchmark model and RIN data as inputs. Further, the AER has disallowed step changes on the basis that no further increase is required from the base year. The practical effect has been to determine an opex that is primarily based on the opex of the average of the top 5 DNSPs of its preferred benchmarking model.

From a procedural viewpoint we are concerned that the AER has relied on a benchmarking report that was published 2 months later than the timeline imposed in the rules[228]. By publishing the report 2 months late, the AER has not provided us with a procedural opportunity to notify the AER of errors prior to the draft determination. It has also limited our time to make a detailed response on the issues contained in the benchmarking report for the purposes of this revised proposal.

From a substantive point of view, we are concerned that an unreasonable weight has been given to the benchmarking analysis undertaken by the AER and this has led to an incorrect assessment of our proposal under 6.5.6 of the rules. We consider that:

- The AER has not given proper regard to other opex factors in its assessment techniques.
- When considering the weight that should be applied to benchmarking, the AER should have had regard to the conceptual limitations of benchmarking analysis, particularly in the Australian context. We outlined these in Attachment 5.33 to our initial proposal.
- We consider the AER has made a number of errors in application of its benchmarking models.

Based on our analysis of the AER's draft decision, we have not revised our proposal to incorporate the AER's reasons on benchmarking analysis. We discuss each of these issues below. Our views draw on expert evidence we have attached to our proposal including:

- Huegin at Attachment 1.06.
- Frontier Economics at Attachment 1.05
- Advisian at Attachment 1.09
- PWC at Attachment 1.10
- Professor Newberry at Attachment 1.07
- Pacific Economic Group at Attachment 1.08.

Role of benchmarking in the context of the opex factors

The annual benchmarking report published by the AER and the benchmark operating expenditure that would be incurred by an efficient DNSP over the relevant period is one of 10 explicit factors that the AER must have regard to when assessing whether forecast opex meets the opex criteria. We consider that the AER has placed undue weight on benchmarking to the exclusion of other factors that it should have regard to. In this way we consider it has given undue weight to benchmarking, particularly in circumstances where the benchmarking analysis that has been undertaken is not robust, including because it is at such a nascent stage of development.

The AER's assessment techniques however are almost wholly dedicated to applying benchmarking tools and models to assess our forecasts. This can be seen in the techniques it identifies on Page 18 of Attachment 7 of its draft decision. Of the seven techniques identified by the AER, five relate to an examination of our costs relative to our peers. The AER has only referred to 2 other techniques which are labour cost efficiency review, and a review of our proposal, which we demonstrated was superficial.

The AER purports to have regard to other opex factors in the table on page 23 to 25 of Attachment 7 of its decision. However the AER's statements against each factor (with the exception of consumer engagement) refer to its benchmarking analysis as demonstration of how it has considered that factor. By way of example, the AER statements on how it considered the actual and expected operating expenditure of the Distribution Network Service Provider during any proceeding regulatory control periods was:

[228] NER, Clause 6.2.7(d).

"Our forecasting approach uses the service provider's actual opex as the starting point. We have compared several years of Ausgrid's actual past opex with that of other service providers to form a view about whether or not its revealed expenditure is sufficiently efficient to rely on it as the basis for forecasting required opex in the forthcoming period.[229]"

From this type of analysis it is clear that the AER has almost solely relied on benchmarking analysis as a deterministic tool. That is, the substitute allowance developed by the AER is in effect determined by the outcomes of the AER's preferred benchmarking model. The AER's reliance on the benchmarking analysis does not meaningfully consider other opex factors that are required to be considered in the AER's assessment of forecast opex in Ausgrid's proposal or in developing its substitute forecast opex, including actual and past expenditure, and the incentive mechanisms that apply. Had the AER considered these factors it may have concluded that our opex in the 2012-13 base year was significantly better than the determination the AER had set in the 2009-14 determination.

Table 25 (page 49) of our initial regulatory proposal for 2015-19 showed that our expected opex for the 2009-14 period was to be $33 million below the efficient forecast opex determined by the AER for this period. This result was the consequence of the efficiency benefit sharing scheme that the AER determined applied to Ausgrid for this period. This scheme incentivised Ausgrid to seek continuous efficiency improvements.

These results have particular relevance for the AER's assessment under opex factor 5 and 8. Instead of having proper regard to our performance against the efficient opex determined by the AER, the AER 'compared several years of Ausgrid's actual past opex with that of other service providers to form a view about whether or not its revealed expenditure is sufficiently efficient to rely on it as the basis for forecasting required opex for the forthcoming period'.[230]

By taking this approach the AER has improperly disregarded its own 2009-14 distribution determination which set the efficient forecast opex for Ausgrid for the 2009-14 period and the incentive scheme that it applied to Ausgrid for this period. It is not sound regulatory practice and therefore it is not reasonable for the AER to have effectively ignored its 2009-14 determination and retrospectively redetermine its view of an efficient level of opex when it has adopted a base year roll forward approach to determining the efficient level of opex. Adopting a base year approach to determining opex creates an unavoidable link between the 2009-14 decision to the current decision, particularly given the formulaic approach the AER has adopted when forecasting opex as demonstrated above.

The 2009-14 determination made by the AER was the basis upon which Ausgrid set its business objectives, operations and management decisions for this period. We failed to comprehend how an actual opex outturn that is below the efficient opex allowance determined under a valid AER distribution determination can subsequently be found to be inefficient, as the AER has stated:[231]

Our findings are consistent with the view that material inefficiency exists in each of the NSW service provider's historic opex.

We maintain that the actual 2012-13 underlying opex is Ausgrid's revealed efficient costs and we reject the AER's assessment that it is not efficient.

In any case, the rules require the AER to have regard to the individual circumstances of the business by requiring the AER to accept the proposed forecast of operating expenditure that reasonably reflects the operating expenditure criteria which include the costs that a prudent operator would require to achieve the operating expenditure objectives and the realistic expectation of costs inputs. Within this context, it is clear that the AER should only ever have contemplated using a benchmarking model(s) and analysis to identify areas where further investigation might be warranted.

The AER did not, as in previous determinations undertake a detailed assessment of components of opex or commission an engineering review of maintenance programs. Instead, the AER relied almost exclusively on an untested benchmarking regime to mechanistically derive very large adjustments to the base year opex for Ausgrid.

We also note that the AER sought to add two additional opex factors one of which is the inclusion of the AER's benchmarking data including from international sources and the other is the AER's economic benchmarking techniques for assessing benchmark efficient expenditure.

In relation to these two additional benchmarking factors that the AER sought to include as opex factor under clause 6.5.6(e)(12), we are perplexed as to the necessity of these factors as consideration of benchmarking is adequately captured under opex factor 4. We consider that the nomination of benchmarking techniques and data as additional factors is not a proper use of the additional factors which may be notified by the AER under 6.5.6(e)(12) and 6.5.7(e)(12). These matters are not separate from opex factor (4), Moreover factor (12) cannot be used to in any way ameliorate the implications of the AER failing to publish its benchmarking report (which would include their techniques and data) in accordance with the timetable under the rules. The rules obviously contemplate that network businesses would be provided with all information relating to its benchmarking two months prior to the AER's draft determination which would allow DNSPs time to consider the AER's techniques and approach prior to receiving the AER's draft

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[229] AER draft decision Endeavour Energy distribution determination 2015-16 to 2018-19 – Attachment 7, November 2014, p.22

[230] AER draft decision, table 7.7

[231] AER draft decision, p. 7-27

decision and preparing the revised proposal. The AER cannot subvert this requirement by seeking to rely upon opex factor 12 which (inappropriately in our view) permits the AER to notify DNSPs of factors the AER considers relevant right up to the submission of the revised proposal.

This supports our contention that the AER has almost solely relied on benchmarking analysis as a deterministic tool, and that it has not substantively considered each factor. We consider this is not the intention of the rules, which seek the AER to undertake a broader examination of a DNSP's proposal.

6.6 Analysis of AER's benchmarking results

In the sections above, we outlined how the AER has incorrectly carried out the required tasks under clause 6.5.6 of the rules. We consider it inappropriate for the AER to base its decision to both reject our forecast opex and determine a substitute based solely on the result of its benchmarking techniques when benchmarking is only one of many mandatory factors the AER must take into account in forming a view on whether Ausgrid's proposed forecast opex reasonably reflects the opex criteria.

We consider significantly more scrutiny should have been given to the results of the analysis and thorough investigation of whether other inherent factors were the drivers of differences. We also consider that it was unreasonable for the AER to deterministically apply benchmarking analysis in the context of the rules, particularly given the extent to which the AER and its consultant, Economic Insights (EI), tried to address environmental variables. The limitations of the AER/EI benchmarking approach, the data used, the model specifications selected, the lack of consideration of alternative models and their implications, and the mechanistic application of the results is discussed in detail in the following sections.

Conceptual limitations with benchmarking

The AER developed its benchmarking approach as a central tenant of the Expenditure Review Guidelines and acknowledged throughout the development of the Guidelines that benchmarking has limitations and should be used as one of several tools to assess expenditure. However, when faced with its first application of benchmarking in the context of a determination, the AER has applied its benchmarking approach with little regard to the uncertainties and limitations it had previously acknowledged. We consider that it was unreasonable and unwise for the AER to give substantial weight to its benchmarking analysis in light of conceptual limitations of benchmarking itself, and even more concerning in the Australian context given the limited data available (i.e. small sample of distributors) and its implications for model specification and econometric techniques.

We raised concerns with the 'fitness of purpose' of benchmarking tools the AER planned to use as part of our determination in our initial proposal. We demonstrated that high level tools such as multi-factor productivity and partial productivity did not meet the key principles for a 'valid' benchmark as defined by the Australian Productivity Commission. Based on our analysis and that of our consultants, our concerns about the AER's benchmarking approach have been well founded.

It is very difficult to use benchmarking to identify whether an observed difference in costs relates to inefficiency or to another driver. This is true in Australia due to the heterogeneous nature of DNSPs in Australia and their operating conditions. As we predicted during the consultation on the Expenditure Guidelines and again in our initial proposal, it is impossible to normalise for these array of differences between DNSPs in Australia and each business circumstances using econometric models. This is a view shared by our consultants at this time of the development of benchmarking in Australia.

The result is that any single benchmarking model will contain elements that will result in bias to toward certain business characteristics, and the results of that model will differ dramatically depending on the model specification used. For this reason, we have always maintained that benchmarking should be used with extreme caution and should not in any circumstances be used in a deterministic way to set operating expenditure allowances.

The question then remains, how should the AER apply benchmarking in the context of the NEM and the rules. There is no definition of benchmarking in the rules. The NER provides only that the purpose of the benchmarking report is to "describe … the relative efficiency of each Distribution Network Service Provider in providing direct control services over a 12 month period". The NER does not provide any more specific guidance on what benchmarking involves (and does not specify methods or techniques that should be used or what should be included in the annual benchmarking report.

The rules refer to benchmarking in rule 6.27 and clauses 6.5.6 (in respect of opex) and 6.5.7 (in respect of capex). rule 6.27 requires the AER to prepare and publish an annual benchmarking report. Clause 6.5.6 refers to benchmarking in the context of the AER's assessment of whether it is satisfied that any forecast of opex reasonably reflects the opex criteria. Clause 6.5.6(e)(4) provides that the AER must have regard to:

a) the most recent annual benchmarking report;

b) the benchmark operating expenditure that would be incurred by an efficient DNSP (clause 6.5.6 (e)(4)); and

in deciding whether or not it is satisfied that a forecast opex amount reasonably reflects the opex criteria.

All we can conclude from the rules themselves is that benchmarking is something the AER must have regard to in making its decisions on operating and capital expenditures. However, we note the rules are silent as to how the AER should have regard to benchmarking and note that the rules do not require the AER to determine the operating expenditure by using a benchmarking model. The fact that benchmarking is one of a list of matters that the rules direct the AER to have regard to indicates that benchmarking is simply one of a number of matters that may be relevant to the assessment of a forecast opex amount, and, in circumstances where the AER does not approve a forecast amount put forward by a service provider, in determining any substitute amount. Further, the rules do not specify what types of benchmarking the AER might have regard to in its analysis.

The rules require the AER to have regard to the individual circumstances of the business and the realistic expectation of costs inputs (clause 6.5.6 (c)(3)) .Within this context, it is clear that the AER should only ever have contemplated using a benchmarking model(s) to identify areas where further investigation might be warranted. Instead, the AER has used an econometric model as a tool by which to determine what it considers to be 'efficient' base year operating costs, and then used these costs to determine its substitute opex for the 2014-19 period.

In June 2008, the Victorian Minister for Energy and Resources submitted a rule change request that would allow for the use of a Total Factor Productivity (TFP) methodology as an alternative economic regulation methodology to be applied by the AER in approving, or amending, determinations for DNSPs.[232]

In response to the rule change request the AER submitted that:

> *This is not only a significant reform program but it is still in its early stages. It is the AER's view that this transition should be given the opportunity to become better established before significant additional change to the underlying regulatory framework is introduced. In particular, one important pre-condition for the use of any TFP-based approach is the development of a full national cost data-based for DNSPs. Such a cost data-base is currently under development by the AER under the new NER provisions in Chapter 6, but this will take some time to be completed. The AER considers that the effective development and implementation of a TFP approach to network regulation is critically dependent on the collection of robust, consistent and reliable long term information about electricity distribution network costs and operational parameters, from a broad range of electricity DNSPs.*
>
> *…*
>
> *Further, it is generally preferable to apply TFP to firms in a relatively steady state environment (i.e. where the future profile of expenditure and demand is relatively smooth compared to historical levels). This is in stark contrast, however, to emerging trends in distribution network expenditure forecasts, particularly those emanating from NSW DNSPs in relation to their upcoming 2009-14 distribution regulatory periods. These indicate that expenditure over the 2009-14 period is foreast to be typically between 50-100 per cent higher than current periods."*[233]

Recognising the complexities of the issues raised by the rule change request, the AEMC instigated a market review into the use of TFP for the determination of prices and revenues. The AEMC engaged EI to provide advice to the AEMC on the use of TFP. In a report dated 9 June 2009, EI noted: "the regulatory data currently available are not fit for the purpose of a robust TFP analysis of the standard required to base regulatory pricing and revenue determinations on".[234] EI went on to say that there was a strong case for developing a well specified and robust national TFP data for the electricity distribution industry and that such a database "would allow potential application of an alternative method of regulation in the future".[235] Further that is was important that definitions and collection methods remain unchanged "for an extended period of time to allow formation of a robust database of sufficient length".[236]

In their 9 June 2009 report, Economic Insights emphasised that it is only by carrying out TFP studies that inconsistencies and gaps in the data are fully identified and understood and that there is an important "learning by doing" in using available data for TFP analysis.[237] The Economic Insight report basically concludes that it will obviously take a number of years before there is a sufficiently long time series available to make TFP-based determinations, but that if the process was commenced as soon as possible, "it may be possible to start making TFP-based regulatory determinations in the next round of reviews or, more likely, the

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[232] Victorian Department of Primary Industries, *Proposed Rules Change to the Australian Energy Market Commission to permit the use of the 'TFP Approach'*, May 2008.

[233] Letter from S Edwell (Chairman, AER) to J Tamblyn (AEMC), 20 August 2008, p 2.

[234] Economic Insights, *Assessment of Data Currently Available to Support TFP-based Network Regulation: Report prepared for Australian Energy Market Commission*, 9 June 2009, p v.

[235] Economic Insights, *Assessment of Data Currently Available to Support TFP-based Network Regulation: Report prepared for Australian Energy Market Commission*, 9 June 2009, p vi

[236] Economic Insights, *Assessment of Data Currently Available to Support TFP-based Network Regulation: Report prepared for Australian Energy Market Commission*, 9 June 2009, p vi

[237] Economic Insights, *Assessment of Data Currently Available to Support TFP-based Network Regulation: Report prepared for Australian Energy Market Commission*, 9 June 2009, p vi

round after that".[238] Without necessarily agreeing with the views of Economic Insights expressed in the 9 June 2009 report, it seems incredible that some five years later, Economic Insights would be of the view that the data that has been collected to date forms an appropriate basis for the determination of opex (or capex) allowances.

In a submission made to the AEMC's market review, the AER stated that it considered it "would be beneficial for a trial of TFP to be undertaken before it is applied in regulatory determinations, to provide greater regulatory certainty on the potential outcomes from implementing TFP and ensure that the TFP framework is well understood by all stakeholders".[239]

In its final report, the AEMC found that a number of conditions would need to be satisfied in order for a TFP methodology to work properly and that such conditions are not likely to be met at that time.[240] The AEMC found that: "Crucially, the current lack of a sufficiently robust and consistent data-set means that it could be too problematic to reconstruct existing data for the purpose of a TFP methodology" and that the lack of data prevents "proper testing of the other conditions needed for a TFP methodology".[241] The AEMC therefore concluded that the "initial focus should therefore be on establishing a better, more consistent data set".[242] The AEMC determined that a two-stage process should be adopted for rule changes. First, an initial rule to require service providers to provide specified regulatory data that would permit the AER to test for the conditions necessary for a TFP methodology and to undertake initial paper trials of the calculations.[243] Only after this had been done could a second stage, involving a detailed design of a TFP methodology and the making of a rule allowing for a TFP methodology to be adopted, be considered.[244]

The AEMC went on to note that the regulatory data provided to the AER under the first stage would assist the AER in meeting its obligation (as it then was) to have regard to efficient benchmarks when making regulatory determinations.[245]

In mid-2009, the AEMC, Economic Insights and the AER were all of the view that there was not an appropriate data-set that would enable a TFP methodology to be used to set regulatory allowances. Further, that it would be some time before any such data set would be available that would even permit the testing of a TFP methodology to assess whether it could even be used as part of setting such allowances. Again, the AEMC, Economic Insights and the AER were all of the view that if there was to be any move to the use of TFP to set regulatory allowances, a trial period would be necessary prior to any implementation. While the AER may not be proposing to use TFP to set Ausgrid's regulatory allowance, the considerations that apply to the use of TFP to set such allowances, apply equally to the use of MPFP to set operating expenditure allowances.

In light of the AEMC materials considered above, it could not have been the AEMC's intention that the 2012 amendments to the rules which the AER says places "significant new emphasis"[246] on benchmarking, would result in the AER determining such a significant component of the regulatory allowance by reference to benchmarking of the type undertaken by the AER. The AEMC essentially says in its final review report that the use of such a benchmarking technique as an option for setting regulatory allowances would need to be the subject of a second step once it has been established that the necessary conditions for the use of such methodologies have been, or are likely to be met, and it is considered that the introduction of such a methodology would contribute to the national energy objectives. This second step has not occurred. As such, the AER cannot, and should not, rely on the benchmarking it has undertaken to fundamentally determine Ausgrid's forecast opex allowance, even putting to one side for the moment the fundamental difficulties with the benchmarking the AER has actually conducted.

More recently, in its April 2013 report on electricity network regulatory frameworks, the Productivity Commission confirmed that the use of benchmarking for electricity networks in Australia was at a nascent stage:

> *major study ranked Australia as a relatively unsophisticated user of benchmarking in electricity networks. Recognising this, the AER has recently reviewed the use and methods of benchmarking by other energy regulators, and is collecting data that would allow it to undertake more elaborate benchmarking. However, the AER should adopt further measures to ensure the successful use and evolution of benchmarking…*[247]

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[238] Economic Insights, *Assessment of Data Currently Available to Support TFP-based Network Regulation: Report prepared for Australian Energy Market Commission*, 9 June 2009, p viii

[239] Letter from S Edwell (AER) to J Tamblyn (AEMC), 30 October 2009, p 1.

[240] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii.

[241] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii.

[242] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii.

[243] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii.

[244] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii.

[245] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii.

[246] AER draft decision - Attachment 7, p 7-13.

[247] Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p. 33

One of the main messages of the Productivity Commission report included:

> *At this stage, benchmarking — which compares the relative performance of businesses — is too unreliable to set regulated revenue allowances. Nevertheless, greater and more effective use of benchmarking could better inform the regulator's decisions.*[248]

Recommendations of the Productivity Commission included:

- The AER's regular aggregate benchmarking of the performance of network businesses should include comparisons of: multifactor productivity – the output of services for given inputs; separate productivity of capital, labour and intermediate inputs. The results should control, to the best extent available, for any significant variations in the operating environments of the businesses, including customer density, line type and length, reliability requirements, and the age of relevant capital assets.[249]
- In any of the next rounds of regulatory determinations, the AER 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.[250]
- The AER should develop and maintain appropriate benchmarking databases and in-house expertise for the technical analysis required to undertake sophisticated benchmarking.[251]
- The AER should collaborate with other leading regulators, academic experts and global commercial specialists to enable robust meta-analysis of electricity network benchmarking results from individual country (and where credible, multi-country) studies.[252]
- The AER should submit its major benchmark analyses of electricity networks for independent expert peert review to establish their ongoing relevance, scientific validity, adoption of best-practice, and to guage the degree of uncertainty in the results.[253]

The Productivity Commission's conclusion on benchmarking as at April 2013, was that there is "little immediate scope for benchmarking to play a decisive role". However, that an increase in benchmarking for diagnostic and informational purposes was likely in the near term in light of the November 2012 rule changes and that, over time, repeated use of benchmarking models will improve the reliability of the models' estimation of nework efficiencies and increase the potential for them to have greater weight in regulatory decisions.[254]

Neither the rules nor the AEMC explain what the AER should use to benchmark DNSPs in order to have regard to benchmarking in their assessment of operating costs. The Productivity Commission found that these is no consensus as to which technique is preferable for benchmarking of utilities more broadly, or distribution networks in particular, and that preferences for techniques vary between regulators around the world and indeed within the same regulators over time. However, the Productivity Commission did identify the criteria by which best practice benchmarking could be identified.

To identify whether the AER's approach to benchmarking is consistent with best practice and therefore fit for purpose in the context of a regulatory determination, our consultants, Huegin, have assessed the AER's approach against the Productivity Commission's best practice measures of benchmarking as outlined in its 2013 report[255].

Huegin found that the AER overall has failed to apply a benchmarking approach that is consistent with best practice. Huegin identifies some areas where the AER approach performs well against the criteria. It finds that the AER fails to meet four out of seven criteria set by the PC to identify best practice measures of benchmarking and fails six of seven criteria established to determine best practice Statistical Practices. The AER performs best in relation to Agency Practices but still fails to meet all criteria. The fact that the AER's approach does not reflect best practice is the first indication that the AER should not have relied on its benchmarking approach and placed such weight on it in making our draft determination. A full explanation of the Productivity

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[248] Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p. 3

[249] Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p. 52 (recommendation 8.1)

[250] Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p. 54 (recommendation 8.5)

[251] Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p. 54 (recommendation 8.6)

[252] Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p. 55 (recommendation 8.9)

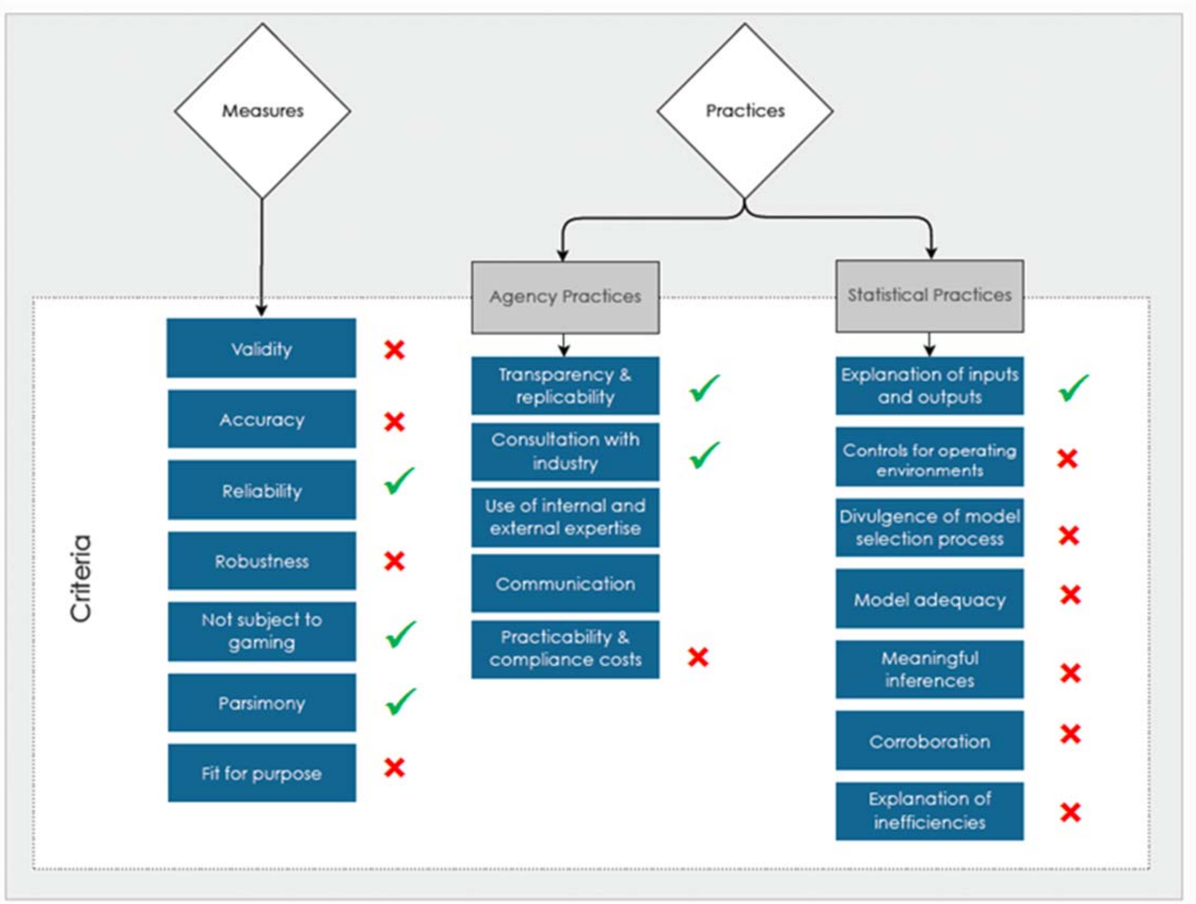
[253] Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p. 55 (recommendation 8.10)

[254] Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p. 334

[255] Productivity Commission 2013, *Electricity Network Regulatory Frameworks, Report No. 62, Canberra*

Commission criteria and Huegin's assessment of the AER's benchmarking practice against this criteria is shown in the Huegin report as exhibit 3.1, reproduced below as Figure 26.[256]

Figure 26 – Huegin's exhibit 3.1 - Benchmarking assessment framework



Adapted from: Figure 4.7 of Productivity Commission 2013, Electricity Network Regulatory Frameworks, Report No. 62, Canberra.

Errors in application of benchmarking

The AER has inappropriately applied its econometric benchmarking model. The results of the model have been applied without applying appropriate safeguards in the form of thorough data preparation and testing of results. This has led the AER to reject and substitute our proposed opex in a manner that does not satisfy the opex criteria in the rules, and subsequently does not meet the NEO and Revenue and the Pricing Principles in the Law.

Furthermore, it was imprudent of the AER to develop a benchmarking model for the specific purpose of deriving a base year opex adjustment given the known difficulties of benchmarking within the Australian context – a context known for its very small sample and for its heterogeneity.

In doing so, the AER did not apply itself in sufficient detail to the consistency of reporting in the RIN or the comparability of international data used in its models, nor did it apply itself to appropriate testing of models and input variables, nor provide sufficient time for peer review of the benchmarking approach.

This has resulted in the AER not only misdirecting itself in its use and application of benchmarking and therefore its application of the rules themselves, but the AER has made a decision to reject and substitute our proposed opex based on error, poor judgment and reckless disregard of the consequences of its decision to the safety and maintenance of our network. By outsourcing its

[256] Attachment 1.06 - Huegin - response to draft determination on behalf of NNSW and ActewAGL - Technical response to the application of benchmarking by the AER, p. 19-27

intellectual role as regulator to its benchmarking consultants EI, the AER has not made a decision that is consistent with the rules or delivered results for customers that are consistent with the NEO.

The following sections outline the errors that have identified and are supported by our experts Frontier Economics, PEG, Huegin, Professor David Newbery, Advisian and PWC.

Use of an untested and non-peer reviewed model

The AER asserts correctly, and we agree that it widely consulted on the benchmarking models it intended to use. However, despite the AER having invited comment, we consider our feedback on its Forecast Expenditure Assessment Guidelines consultations was not appropriately incorporated into its final document. We noted the untested and immature nature of the approach the AER intended to use, and suggested a very cautious approach to its use in regulatory decision making.

As this is the first time the AER had relied on such models it should have released the models in advance of them being applied to regulatory determinations. This would have enabled proper peer review.

Furthermore, we contend the AER departed from its final Forecast Expenditure Assessment Guideline by making substantial changes to the way it undertook benchmarking approach for the draft determination. Specifically, this included changes to the techniques utilised, the model specification being used and the data used to derive the results. As a result the models are not consistent with those set out in the AER's Guidelines, and upon which consultation was based, and as a result the models that have been used have not been subject to consultation or peer review at all.

As such, the AER did not follow proper process and knowingly applied an immature and under-reviewed model to derive substantial cuts to operating expenditures for all four companies in NSW and ACT. Not only are the opex adjustments greater than any imposed by a regulator internationally which would naturally highlight a need for a cautious approach, the AER relied on the model exclusively as a measure of inefficiency and basis for adjustments to the base year allowance.

Had the models been released for proper review prior to their application in the context of the draft determination, such large adjustments would not have been made as the AER would have been made aware of the false confidence it had in the modelling results.

Inconsistency of results

Sensitivity of the models selected and their specification has been found to significantly influence the relative ranking of efficiency results. Models run by Economic Insights, PEG, Huegin and Frontier Economics all demonstrate the variation in results that can be achieved through the use of different modelling techniques and model specifications. The AER/EI was misdirected when it rejected models that did not confirm its expected results. This is evident asthe extent of the variation in outcomes itself indicates the poor explanatory power of the model as a proxy for real operating costs of the businesses. [257]

The AER and its consultant Economic Insight argue that the selected model was tested with three other models and the results were confirmed as being similar across all. We argue that such confidence is misplaced as the models are effective variation of the same model rather than separate and distinct models. The AER and EI state that in their opinion all material parameters have been taken into account and as a result, the relative performance of the networks relates to management performance (inefficiency) and not to other environmental factors that have not been addressed within the model. This finding has been directly refuted by Frontier Economics in their expert report where they demonstrate that when variables are incorporated into the models to test for heterogeneity (company specific factors) and efficiency, Frontier Economics find that almost all of the variance can be attributed to the heterogeneity of the sample.[258]

False Frontier

The AER/EI has applied an average of data reported from 2006-2013 in its SFA model to lessen the impact of any year on year variation. The comparison of the NSW / ACT distributors with the frontier businesses as of 2009 has the effect of comparing the distributors at the time of its greatest difference – the first year of higher expenditures in NSW associated with higher capital expenditure, and mid-period for the frontier firms. The use of any other averaging period (i.e. 2008-2013, 2009-2013, etc. and up to 2013 alone) produces different results that show a more contracted spread of results.

The use of averaged opex data sets the frontier as at 2009 and rolls it forward for CPI. Since 2009, the increase in operating expenditure of the frontier businesses has been greater than CPI, and thus, the target frontier is set at a level that the frontier

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[257] Attachment 1.05 - Frontier Economics - Review of AER's econometric models and their application in the draft determination for Networks NSW, p. 80-84.

[258] Attachment 1.05 - Frontier Economics - Review of AER's econometric models and their application in the draft determination for Networks NSW

businesses even now, cannot achieve.[259] Evidence from the SA Power Networks submission shows significant increases in operating expenditure forecast for the forthcoming period as a result, in part, of higher maintenance costs driven by higher failure rates and inspection costs. [260]

The use of 2009 data for Victorian DNSPs fails to capture the significant financial impacts of the outcomes of the Victorian Bushfire Royal Commission on both recurrent and short to mid-term expenditure. We note the concerns of independent regulators in Victoria about the deterioration in performance of the Victorian DNSPs, as demonstrated by increases in asset failures and fire starts over three successive years to 2013. In addition, backlogs in both maintenance tasks and safety programs in maintenance tasks that have been highlighted in their recent report[261]. Advisian also note that the benchmarking incorrectly assumes that reliability performance, and in some cases safety perforamnce, has been stable over the analysis period.[262]

We are concerned that by using an average operating cost the AER has established a false frontier – one that even those businesses on the frontier in 2009 can no longer meet. We argue that the false frontier is a dangerous benchmark as it does not represent a sustainable level of expenditure for a network business operating to meet modern safety, OH&S and asset management obligations.

In terms of Economic Insights model results, Huegin has found that if the model is re-run using 2013 data only, the frontier moves towards the NSW DNSPs by 9% which has the effect of reducing any opex adjustments made by the AER by 9% for each business. Huegin does not contend that the frontier reflects efficient costs, but has made these calculations to demonstrate the real consequence of the AER's decision to apply averaged variables, and apply the result of the model mechanistically.[263]

The mechanistic application of results from the model takes little account of regulatory changes over time or investment cycles that have driven expenditure in the past, or will drive expenditure in the future.

Poor variable selection

There is significant debate around the variables that should be used in econometric modelling of cost functions of electricity distributors. The variables that best represent inputs to the cost function or the outputs of provision of electricity supply by distributors in Australia are not universally agreed. Variables can be selected in two ways. They can be selected up front based on intuition or precedent or by testing a range of parameters to determine which is most statistically significant. The AER and its partner EI determined the input and output variables using intuition and assessment of inputs contributed by the business and outputs seen by customers.

A contrasting method to identify appropriate input and output variables is to recognise a wide range of potential inputs and determine through statistical analysis which of those is statistically significant, and weed out those that are not significant, and weed out those that are not significant. This is the method preferred by our consultants PEG.

In either case, the selection of variables is limited to data gathered. Despite the significant collection of data via the RIN, EI was unable to make use of the bulk of the data because its preferred modelling approach - Cobb Douglas SFA model - required a large data set, which in turn limited the availability of variables that could be used within the modelling to those that were consistently reported across selected jurisdictions.

PEG argues in its expert report (Attachment 1.08) that the failure to test a range of variables for significance due to the limitation of the comparability of the Canadian, New Zealand and Australian data set has led to significant variables being omitted from the models, and differences in performance being attributed to efficiency or lack thereof, rather than correctly attributed to omitted variable bias. Variables that PEG found to be significant in their study conducted for the AER using Australian and US data were not able to be included in the EI models due to the lack of comparable data available in the Canadian / New Zealand data set.[264] In this case, the use of international data from Canada / New Zealand had a profound negative effect on the explanatory power of the EI model.

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[259] Attachment 1.06 - Huegin - response to draft determination on behalf of NNSW and ActewAGL - Technical response to the application of benchmarking by the AER, p.46

[260] SA Power Networks – Determination 2015-2020. (https://www.aer.gov.au/sites/default/files/SAPN%20Regulatory%20Proposal%202015%E2%80%932020.pdf) S. 9.2.1 p. 87

[261] Safety Performance on Victorian Electricity Networks, 2013. http://www.esv.vic.gov.au/Portals/0/about%20esv/FINAL%20Annual%20Safety%20Performance%20Report%202013%20V1.PDF

[262] Attachment 1.09 - Advisian - Review of AER benchmarking, January 2015, p.3

[263] Attachment 1.06 - Huegin - response to draft determination on behalf of NNSW and ActewAGL - Technical response to the application of benchmarking by the AER, p.38

[264] Attachment 1.08 - Pacific Economics Group (PEG) - Statistical Benchmarking for NSW Distributors, Jan 2015, p.52.

Australia is a particularly difficult region in which to benchmark electricity distributors due to the small and heterogeneous sample. The heterogeneity can only be overcome by inclusion of environmental variables into the selected model. However, the small data set available in Australia limits the number of variables that can be considered. Due to this limitation, significant effort is required to ensure that differences within the data set are minimised and that differences in activity type, scope, and regulatory requirements are normalised prior to the data being used for modelling.

Like PEG above, Advisian and Huegin notes with concern the impact of excluding meaningful variables. Huegin on page 40 of their report (referred to as Exhibit 4.4 reproduced below as Figure 27) assess the drivers of network costs and test them against the variables selected by the AER/EI models. Of the three variables included in the model, line length was assessed as having the strongest relationship with cost, with numbers of customer having a moderate impact on cost. Peak demand was assessed as having very little relationship to cost at all.

Figure 27 – Exhibit 4.4 - Huegin Consulting's assessment of cost categories, cost drivers against AER benchmarking variables[265]

Cost Category	Contribution to Industry Costs*	Activities	Primary Drivers	Customers	Peak Demand	Line Length
Maintenance Costs	17%	Inspection	Schedule, design, location	None	None	Moderate
		Routine corrective	Design, schedule	Moderate	None	High
		Non-routine corrective	Failure rates, design	None	None	Low
Emergency Maintenance	10%	Assisted	Exposure, proximity	Low	None	Moderate
		Unassisted	Weather	None	None	Moderate
Vegetation Management	13%	Audit	OH network, location, terrain	None	None	Low
		Clearance	OH network, location, vegetation growth rate	None	None	Low
		Tree trimming	OH network, location, vegetation growth rate	None	None	Low
Corporate Overheads	17%	Executive	Scale	Moderate	None	None
		Legal, HR, Finance	Employees, energy served, network service area	Moderate	None	Low
		Regulatory, insurance, debt and equity raising	Energy served, revenue	Low	Moderate	Low
Network Overheads	39%	Network control & systems operations	Location, complexity, level of automation	High	High	Moderate
		Network management	Design complexity, location	Moderate	Low	Moderate
		Network planning	Location, design complexity	Moderate	Moderate	Moderate

Furthermore, Advisian have also identified missing cost drivers and have stated that the variables utilised do not reflect a reasonable set of variables available in the Australian RIN information that contribute signficantly to differences in cost drivers for the NSW DNSPs.[266] For example:

- Asset types and volumes (line type, voltage and lengths, installed capacity, transmission point connections)
- Vegetation management differences (responsibility, presence of vegetation, growth rates)
- Spatial density

[265] Attachment 1.06 - Huegin - response to draft determination on behalf of NNSW and ActewAGL - Technical response to the application of benchmarking by the AER, p.35

[266] Attachment 1.09 - Advisian - Review of AER benchmarking, January 2015

- Reliability trends
- Physical asset ages (rather than remaining economic lives).

The limitations of the Ontario data has meant the following drivers of opex have not been taken into account:

- Asset age
- Climate and environment
- Customer demographics
- Network design
- Network voltages
- Network accessibility
- Network utilisation
- Reliability standards
- Scale
- Policy and regulation; and
- Physical environment in which the business operates.

These factors will all explain part of the opex differences between networks and have not been picked up in the AER's analysis. Not all factors are significant as explanations of the business costs but they underline the importance of treating the results of modelling as indicative only, and something that should trigger further investigation rather than treated as a definitive calculation of efficiency.

We asked Advisian to assess the validity of the variables as real cost drivers. Advisian argue that changes must be made to the AER's model to better reflect differences in the volume and nature of the assets that are operated and maintained by each distributor in order to remove the influences of productivity differences which relate to geographical and inherent network design issues that are outside the control of the businesses.

Advisian note that in relation to the Victorian and South Australian DNSPs to whom the AER has made direct comparisons, the NSW DNSPs must each maintain substantially more assets per customer at a substantially lower unit cost per asset.[267] Advisian highlight three principal factors relating to asset volume and type that are highly material to determining the efficient Opex requirements for the business which they argue have not been appropriately taken into account in the model for the purpose of determining efficient opex.

- The use of total installed zone and distribution transformer capacity rather than ratcheted maximum demand to recognise differences in security requirements, utilisation and load distribution across the network;
- The relativity between route length and circuit length as well as a correction for rural distributors to account for the lower Opex required to maintain SWER line in comparison to conventional three phase distribution lines. (This is also supported by Frontier[268]); and
- The recognition of the impact of spatial density (customers per km2) as distinct from linear density (customers per km) on the nature and configuration of electricity distribution networks, and consequently on the efficient Opex requirements for a distribution network.[269]

The AER reviewed the Weighted Average Remaining Life (WARL) of the DNSPs and stated that it did not need to include an operating environment factor for differences in asset age, and made the statement that "Ausgrid does appear to have a lower WARL than Endeavour Energy and Essential Energy, but its WARL is high than CitiPower's and SAPN's. Ausgrid's WARL is also only slightly lower than AusNet's and Powercor's. Therefore, we are not satisfied an adjustment for asset age is warranted".[270]

Advisian do not concur with the AER's findings that "The age profiles of the NSW service providers and the comparison service providers are similar, and therefore should not lead to material differences in their Opex". Advisian's analysis shows that "the AER's

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[267] Attachment 1.09 - Advisian - Review of AER benchmarking, January 2015, p.79

[268] Single Wire Earth Return (SWER) line consists of widely spaced poles with a single high tension conductor strung between and was historically used as an inexpensive means to electrify rural areas. In comparison to conventional three phase 11kV or 22kV distribution lines, SWER lines typically require less than half the poles due to average spans in the order of 200m in length and one quarter of the total conductor length. From an opex perspective, this translates to approximately half the pole inspections and minimal maintenance of pole top structures. However there is generally no opex benefit for 'per km' line inspections.

[269] Attachment 1.09 - Advisian - Review of AER benchmarking, January 2015, p. 52-53.

[270] AER draft decision, s. 7, p. 128-129.

assessement of the relative 'age' of the NSW networks is fundamentally misleading when compared to reported asset age profiles contained in the RIN information provided by the businesses."[271]

PEG also found that substation capacity was a much more statistically significant variable than peak demand in their study for the AER and in other studies they have conducted but this variable could not be used in the Economic Insights (EI) model due to the absence of comparable Canadian data.

Previous analysis of the New Zealand electricity distributors undertaken by EI demonstrates the ways in which the input and output variables can be treated to account for differences between distributors. [272] For example, in this study, line length was scaled by operating voltage. In the report EI also discuss the desirability of using reliability performance as an output variable. The omission of reliability in EI's current modelling was highlighted by Advisian as further evidence of the inadequacy of the analysis undertaken.

Use of dummy variable

Economic Insighs accept that there are differences between the operating environments in various countries and as a result included a dummy variable designed to take account of country specific differences. We do not consider that the use of a dummy variable has sufficiently addressed the inherent differences in the international data. This view is supported by Frontier Economics who argue that:

> *(s)imply including country dummy variables is an insufficient way of controlling for specific differences between networks and between countries. The dummy variable simply shifts the intercept terms, without affecting the slope coefficients, which…is an insufficient method of controlling for differences.*[273]

Professor Newbury is also critical of the use of dummy variables as the panacea for inter-country operating differences and says that:

> *Including a dummy variable in the model specification does not necessarily control for these within and across country differences. A dummy variable only controls for level differences between datasets not cost relationship differences.*

It is the different relationships between environmental factors and cost that is precisely why Frontier recommend that substantial effort is spent preparing data properly before it is applied in a model. This view is supported by Newbury in his separate report where he raises concerns that the data relied upon by the AER has not been sufficiently normalised before being used in the modelling, and notes that the "failure to normalise the data may lead to unreliable results, and potentially the choice of inappropriate models of specifications."[274]

Insufficient data preparation

There is little evidence supplied by the AER or EI that they have investigated the suitability of the data they have used for benchmarking purposes. Our analysis and the views of our expert consultants reveal a number of issues with the data which reduce it accuracy, coherence and suitability. These are:

- There are errors in the international data, and issues with comparability to Australian data.
- There are errors in the adjustments made to Australian data utilised.
- The RIN data by NEM distributors have not been reported consistently. No analysis has been undertaken of the effect of cost allocation and capitalisation policies.

In respect of international data, EI used data from Ontario as part of its modelling. It is unclear what level of data review was undertaken by the AER or its consultants as our consultants Frontier, were quickly able to identify data errors in the Canadian data set. The presence of such errors suggests a worrying lack of regard for the importance of proper data preparation for an effective benchmarking exercise.

These concerns have been further justified as the opex used to compare Canadian firms with those in Australia has been found not to be comparable. The AER and EI have failed to investigate the consistency of the Ontario data closely enough. Neither EI nor the AER present any information about detailed data consistency checks.

PEG was involved in the development of the Ontario data and has advised us that operating costs in the Ontario sample:

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[271] Attachment 1.09 - Advisian - Review of AER benchmarking, January 2015, p.77

[272] http://www.economics.ubc.ca/files/2013/06/pdf_paper_erwin-diewert-electricity-distribution.pdf

[273] Attachment 1.05 - Frontier Economics - Review of AER's econometric models and their application in the draft determination for Networks NSW, p.43

[274] Attachment 1.07 - David Newbery, Cambridge Economic Policy Associates: Expert report, Jan 2015, p.12.

- Exclude costs of maintaining substations with primary voltage exceeding 50kV.
- Include costs associated with public lighting, meter provision, meter reading, and customer connections.[275]

Frontier also point out the differences in the definitions of other variables used in the analysis. Frontier provides the definitions of the variables used for reporting data in Australia, New Zealand and Ontario in Table 9 of their report[276]. The differences in definitions are clear. For example, the circuit kilometers definition in New Zealand specifically states that "when a pole or tower carries multiple circuits, the length of each of the circuits is to be calculated individually". In direct comparison, the definition in the RIN specifies that "…each SWER line, single-phase line, and three-phase line counts as one line". In relation to customer numbers, the definition used in New Zealand requires DNSPs to include inactive accounts, but in contrast, the RIN states that "only NMIs for active customers may be counted".[277]

The fact that these differences have come to light after the AER has published its draft determination is concerning, as it highlights the lack of due diligence that was undertaken when reviewing the data fitness for inclusion in their analysis.

The increase in the sample size has done little to add meaningful comparators to the data set. Many of the businesses in Ontario are municipal utilities servicing small communities. Economic Insights tried to address this issue by using a 'medium' data set in their analysis. However, even the 'medium' population contains 41 distributors that serve between 20,000 and 100,000 customers, and only 12 companies in Ontario and New Zealand that serve more than 100,000 customers. In comparison, the average sized network in Australia serves more than 730,000 customers.

Frontier Economics undertook a further review of the comparability of data between Ontario and Australia and report that Australian distributors are on average four times larger than the Ontario distributors and only one business of 86 in total is comparable in size to Australian businesses when comparing circuit length.

Advisian put this comparison in another way by noting that Ontario is approximately 60% of the area of Queensland with the largest business, Hydro One serving approximately 75% of the province. This leaves approximately 70 DNSPs serving a relatively compact area that is comparable in size to either Victoria (5 DNSPs) or New Zealand (27 DNSPs).[278] They also noted that "the Ontario Government's Ontario Electricity Distribution Sector Review Panel (OEDSRP) does not consider either its individual DNSPs or industry structure to be comparable t the other provinces within Canada, or states in Australia."[279] It is therefore concerning that the AER has ignored this advice and used data from Ontario in a benchmarking model developed for the express purposes of identifying the relative efficiency of Australian DNSPs.

Finally, Advisian highlight the most stark comparison of all. They argue that the issue that distinguishes Australia from many overseas comparisons is the large variation in spatial customer density between the 13 Australian DNSPs which ranges from 0.4 customers / km^2 (Ergon Energy) to 2050 customers / km^2 (Citipower), - a ratio of 1 : 5,125. This ratio is significantly greater than the linear density ratio of 4.3 customers / km (Ergon Energy) to 75 customers / km (Citipower) - a ratio of only 1 : 17.4.[280]

As well as being significantly smaller than the Australian networks the Ontario networks face:

- Different environmental factors such as maximum and minimum temperatures and extent of snow fall.
- Different legal, industrial relations and regulatory regimes.
- Significantly different networks in the extent of underground cables, length of high voltage network and circuit length per customer.
- Different relationships between opex and cost drivers.

These differences in cost structures and drivers between the Australian and Ontario based business are significance as the results of Economic Insights' Cobb Douglas SFA appear more similar to the results for Ontario alone than to the results for either Australia or New Zealand. Frontier Economics tested the comparability of the data from a statistical perspective (referred to as 'poolability').

[275] Attachment 1.08 - Pacific Economics Group (PEG) - Statistical Benchmarking for NSW Distributors, Jan 2015, p.54

[276] Attachment 1.05 - Frontier Economics - Review of AER's econometric models and their application in the draft determination for Networks NSW, p.45.

[277] Attachment 1.05 - Frontier Economics - Review of AER's econometric models and their application in the draft determination for Networks NSW, p.45.

[278] Attachment 1.09 - Advisian - Review of AER benchmarking, January 2015, p.15

[279] Attachment 1.09 - Advisian - Review of AER benchmarking, January 2015, p.25

[280] Attachment 1.09 - Advisian - Review of AER benchmarking, January 2015, p.29.

We tested for the poolability of the data from the three countries by re-estimating EI's preferred model with the addition of variables that could pick up differences between the countries in the values of the elasticity on the four main drivers of costs (customer numbers, circuit length, ratcheted maximum demand and share of underground cables) as well as time trends….(W)e tested the hypothesis that these deviations can be assumed to be zero, in which case the pooling of the data for the three countries is justified.

The results … of this poolability test overwhelmingly reject this hypothesis.[281]

Frontier also undertook a review of differences between distributors across the three countries and quickly reached the conclusion that given the vast differences in scale and cost structure when combined with the lack of data consistency across and within countries, the differences purported to be efficiency in the EI model is more likely to relate to latent heterogeneity.

In relation to the RIN data, the Australian data itself is not free of error. The costs reported by NEM distributors have not been reported consistently between businesses.[282] The audits conducted by each company reviewed the consistency of reporting and compliance with the guidance provided by AER within each company, but did not compare data interpretations and reporting practice between companies.

PWC (Attachment 1.10) was engaged to review the data relied on by EI in the economic benchmarking RIN (including each DNSP's 'Basis of Preparation' documentation) and found that:

- Inputs used to calculate network length were subject to different interpretations across businesses.
- There are differences in cost allocation methods which has implications for costs assigned to opex (as opposed to capex).
- There are material differences in accounting methodologies and application of accounting standards which have the potential to impact the size of opex used in EI's calculations.

The scope of activities between distributors is also not comparable. One example is vegetation management where this activity is jointly managed by distributors and local councils in Victoria, but solely by distributors in other jurisdictions like NSW. Furthermore, vegetation management costs also correlate with rainfall which varies significantly across jurisdictions. Without accounting for differences in scope or the inherent costs driven by network location, the AER is comparing higher cost businesses with lower cost businesses and attributing differences to management performance (efficiency) rather than inherent and uncontrollable differences between businesses. With this in mind, the AER's use of vegetation management costs to validate the benchmarking outcomes across the NSW DNSPs would appear misguided.

In relation to the AER comparisons of vegetation management costs specifically (category benchmarking), Advisian argues that "the AER has relied on an erroneous and inconsistent assessment of Essential Energy's vegetation management expenditure to support its conclusions that the NSW DNSPs are inefficient."[283] They go on to identify a number of analytical inconsistencies in the AER's 'detailed review' which include:

(i) The failure to fully consider the vegetation management information provided by the DNSPs in respons to the AER's RIN requirements;

(ii) The failure to account for differences in DNSP responsibility for vegetation management works between jurisdictions;

(iii) Analytical inconsistencies and errors in the calculation of overhead route kilometers;

(iv) The ultimate reliance on a single year result for one business (Essential Energy) to infer that all NSW DNSPs are inefficient; and

(v) Reliance on an erroneous assessment of the reliability impact of vegetation outages to infer that the impact of vegetation outages is increasing.[284]

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[281] Attachment 1.05 - Frontier Economics - Review of AER's econometric models and their application in the draft determination for Networks NSW, p.24

[282] Attachment 1.09 - Advisian - Review of AER benchmarking, January 2015, p.39

[283] Attachment 1.09 - Advisian - Review of AER benchmarking, January 2015, p.4

[284] Attachment 1.09 - Advisian - Review of AER benchmarking, January 2015, p4

Frontier also point to a lack of specification within the RIN compared to that which is common in other jurisdcitions, namely Great Britain. Frontier argues a step change is required before data is of suffiicent quality to be able to be used in the context of a price review.

Post-model adjustments

The only environmental variable that has been directly considered by EI is the simple proportion of overhead and underground assets. All other adjustments have been made outside the model.

Professor David Newbury in his report considers that the environmental differences, "particularly the capitalisation policies and greater proportions of high voltage lines, are sufficiently material to be made either through the use of explanatory variables in the modelling or via adjustment prior to conducting the modelling. (Newbury) consider(s) that making adjustments after the modelling for material differences in companies' cost reporting is not in line with the approach used by Ofgem, the UK electricity and gas regulator, which is considered a leader in the use of comparative benchmarking."[285]

Both Huegin and Frontier agree that the post-modelling adjustments are unlikely to be sufficient to account for the different operating conditions.[286]

No reasonableness check of results

A proper application of benchmarking would involve a reasonableness check of the results of the models. This is a process the AER should have conducted given the magnitude of the opex reductions which are unprecedented internationally[287] and the manner in which it has been applied retrospectively. Frontier argue that this fact alone should have prompted a more moderate response from the AER.

Frontier compared Economic Insights' modelled efficiency rankings with that determined by the Ontario Energy Board in its latest efficiency analysis completed in July 2014.[288] Frontier found that

> *the disparity in the effiicency ranking of the Ontarian networks, as between the OEB and the AER, casts strong doubt over the AER's results in relation to the Ontarion networks. Given that one Ontarian firm, Hydro One Brampton network Inc., sets the efficiency frontier in the AER"s analysis for the networks in all three jurisdictions, there would seem to be considerable doubt over the reliability of the AER's benchmarking analysis.*[289]

The AER's decision to apply base year opex adjustments recommended by the EI model in full from the first year of the period is not consistent with regulatory practice in other jurisdictions. Newbery, Huegin, PEG and Frontier all point to the manner in which Ofgem has acknowledged differences in modelled outcomes, and applied a range of different models and weighted the results when determining adjustments to be made to businesses allowances. Newbery points out that the largest adjustment made by Ofgem in its most recent distribution price review was 11% and was justified by Ofgem on the basis of the length of time the networks have been subjected to comparative assessment and relative convergence achieved over that time[290]. In contrast, the AER has made adjustments three and four times as large in its first application of an untested model.

As a further comparison with Ofgem, in its most recent decisions Ofgem gave direct weight to the distributors costs in their analysis in addition to applying weights to its own models. In contrast, the AER has not applied any weight to the NSW DNSPs cost submissions and has simply substituted its own calculation of efficient costs using a single top-down benchmarking model.

In Norway, the regulator also applies a direct weighting to the distributors costs of 40% with the remaining 60% weighting being applied to benchmarking results.[291] No such balancing of the benchmarking outcomes with distributors costs has been made by the AER

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[285] Attachment 1.07 - David Newbery, Cambridge Economic Policy Associates: Expert report, Jan 2015, p.12

[286] Attachment 1.05 - Frontier Economics - Review of AER's econometric models and their application in the draft determination for Networks NSW, p.98; also Attachment 1.06 - Huegin - response to draft determination on behalf of NNSW and ActewAGL - Technical response to the application of benchmarking by the AER, p.44

[287] The PEG report (Attachment 1.08) outlines the history and practice of benchmarking internationally. PEG's survey did not identify any precedent that would support the approach taken by the AER in this draft determination.

[288] It is interesting to note that the OEB was assisted by PEG in this analysis

[289] Attachment 1.05 - Frontier Economics - Review of AER's econometric models and their application in the draft determination for Networks NSW, p.62

[290] Attachment 1.07 - David Newbery, Cambridge Economic Policy Associates: Expert report, Jan 2015, p.24

[291] Attachment 1.05 - Frontier Economics - Review of AER's econometric models and their application in the draft determination for Networks NSW, p.105.

The Ontario Energy Board have also applied benchmarking in the context of price reviews but have not translated measured relative inefficiency between networks mechanistically into cost reductions. The OEB moderate the application of the model results by assigning businesses to tranches based on their relative performance and by applying significantly smaller adjustments to each tranch over time. In its last review, the largest adjustment factors applied as a stretch factor was 0.6% which is materially less onerous than the efficiency discounts proposed by the AER. Frontier points out in their report that "the OEB views the stretch factors it sets as designed to encourage networks to become more efficient over time, and not punitive measures for inefficiency." In contrast, the AER's proposal to cut opex by up to 40% for some distributors. When seen in dollar terms, the comparison is stark. For illustrative purposes, we take Ausgrid as an example, The application of a 0.6% stretch factor (applied to the worst Ontarian performer) equates to a 5-year revenue cut for Ausgrid of $73 million[292] compared to the proposed opex cut (effectively a revenue cut) for Ausgrid of $1,130 million proposed by the AER. In dollar terms the AER's reduction to opex is 15 times more onerous in revenue terms. The magnitude of the cost reductions applied by the AER cannot be seen as anything less than punitive and completely unreasonable when compared internationally.

In New Zealand, the Commerce Commission's consultant identified a substantial range (around 30%) in companies' efficiency but acknowledged the variable quality of the available data and residual uncertainties and to minimise risk reduced the range of relative productivity and profitability factors to –1, 0 and 1 per cent".[293] Using the example of Ausgrid once again, an X-factor of 1% applied to Ausgrid's 2014 proposal would equate to a reduction of proposed revenue of about $122 million over 5 years. In contrast, the AER's proposed cuts to opex of $1,130 million are 9 times more onerous that that applied by the New Zealand regulator to the worse performers.

The imposition of cost reductions of the scale contemplated by the AER is without precedent in the countries that our experts surveyed. So too is the retrospective nature of the cost reductions. In contrast, our experts found evidence that regulators overseas acknowledge that changes to business operations take time and where stretch factors were applied or reductions to cost allowances imposed, they were applied in a way that reflected the regulator's judgments about the speed and extent to which a business can change its operations to reflect better performance. Newbery quotes from Meyrick and Associates who advised the New Zealand Commerce Commission in its 2004 electricity distribution networks price control and argued that it was "unrealistic to expect lines businesses to be able to remove large productivity gaps in a short space of time".

The AER has failed to apply simple sense checks to the results. For example, using the coefficients from the SFA model, the model suggests Endeavour should be allowed only 44% of the costs that would be provided to Citipower on a normalised basis. For Ausgrid, the rate is 60% of the equivalent Citipower costs.[294]

Due to the errors in the models and the data, Frontier recommend that the outcomes of the EI model be put aside and play no role in the AER's final determination. Huegin too consider that the results of the EI model are not a credible representation of base year expenditure and should not be used.

Based on this evidence we consider that the benchmarking analysis contains errors, and accordingly we have not revised our proposal for the AER's analysis.

No reasonableness check of substitute opex allowance

The AER's substitute allowance for opex was derived from its benchmarking analysis. The AER used the results of a model specification developed by its consultant to identify the average opex of the top 5 'frontier firms' in the analysis. The AER then applied a 10 % increase to this level of opex to recognise factors that may increase the costs of providing services in our network. To calculate opex from the base year, they applied a rate of change factor derived from a formula and a 'step change' relating to the leaseback of Ausgrid's head office building.

In deriving the substitute the AER has not considered our activities and costs in undertaking those activities, but rather developed a quantum of opex based on a single benchmark model. As demonstrated in this section and referenced attachments, the benchmarking analysis is inherently limited and can never fully account for differences between DNSPs.

The AEMC has been clear that the AER has an obligation to develop a reasonable substitute. In this case the test of reasonableness is whether the allowance is sufficient to enable a prudent and efficient operator to achieve the opex objectives. Rather than undertake a reasonableness check of its benchmarking analysis, the AER states:

[292] Proposed SCS revenue $12,189M x 0.6%

[293] Newbury Report p.26 (Attachment 1.07) refers to Meyrick (2003, p63), *Regulation of Electricity Lines Businesses, Analysis of Lines Business Performance – 1996-2003*, a report prepared for Commerce Commission, Wellington New Zealand.

[294] Attachment 1.09 - Advisian - Review of AER benchmarking, January 2015, p.42.

… we determine a service provider's opex allowance at the total level. We do not seek to interfere in the decisions a service provider will make about how and when to spend this total opex allowance to run its network, including the particular legal obligations it enters into to do so. The service provider is free to choose how to manage its allowance.

It is not sufficient to state that a DNSP is free to choose how to manage its allowance, without providing the DNSP with the allowance necessary to meet the objectives. As we outlined in Chapter 1, we have serious concerns about the AER's view that it is only required to make a holistic determination on the total revenue allowance and that it is not its role to interfere with Ausgrid's decision as to how Ausgrid will spend its expenditure allowance. We consider this an error in the AER's assessment approach and the principle underlying this approach. The rules specifically set out how the annual revenue requirement is to be calculated, with reference to constituent decisions of each of the building block of this revenue requirement. We consider that examining and assessing the reasonableness of the components of our forecast opex (i.e. maintenance costs, property costs etc.) would not necessarily amount to undue interference in the eventual Ausgrid's decision on how the expenditure allowance would be spent. It is artificial to pretend that a 'holistic' determination imposes any less of interference on the DNSP as to what projects it may spend on than a determination that is based upon an examination of the components of the total forecast opex proposed.

The individual circumstances and obligations of a business must be considered rather than constructing a hypothetical benchmark DNSP. In relying on benchmarking and high level analysis the AER has not understood the implications of its decision on safety, reliability and our ability to efficiently meet our obligations as a DNSP.

We sought advice from R2A Due Diligence Engineers in regard to safety impacts of the AER's decision (Attachment 1.13) and Jacobs Group Australia in relation to reliability and prudency (Attachment 1.16).

R2A noted:

If Ausgrid were to operate within the constraints of the AER's draft determination, then in the short term, the number of safety incidents, especially to employees, is expected to spike……In the longer term, this analysis indicates that for the foreseeable threats to members of the public considered in this review, an increase of around 3.4 per annum in the fatality rate from network hazards would most likely occur. In addition, the likelihood of the Ausgrid network starting a catastrophic bushfire (meaning 100 fatalities and 1,000 houses lost) more than doubles as a result of increased equipment failures due to longer inspection cycles.

Jacobs expressed the following views:

In our opinion, the AER does not appear to have apposite consideration of the impact that the revised expenditure levels have on the risk exposure of the NSW DNSPs.[295]

and

based on our review we consider that the AER has not duly regarded the associated risk profiles. In Jacobs' view the expenditure and risk profiles of the NSW DNSPs are directly linked. Thus, it would appear imprudent to reach a position on expenditure without considering risk profiles. From our understanding of the NSW DNSP's risk profiles gained throughout the course of this review we consider that, if imposed, the AER's Draft Determinations could potentially lead to a situation where the businesses are unable to effectively mitigate the risks associated with their network assets. Critically, in our review of the AER's discussions supporting the Draft Determination expenditure reductions we were unable to observe robust consideration of critical risk factors such as bushfires and public safety; where, in Jacobs' opinion the overarching thread focuses on costs versus reliability of supply.[296]

We consider that a reasoned decision maker would consider the risks that would arise from its substitute opex allowance. One means of doing this would be to assess the activities that the DNSP has identified as being required to achieve the opex objectives. The AER should be able to identify if there is a particular activity or program that could be curtailed or limited while still enabling the DNSP to achieve the opex objectives. If all the activities are sound, the AER might then assess whether there is any efficiency that can be derived in delivering those activities. If the AER is unable to identify a source of inefficiency, it would then need to review its substitute allowance in that light.

This is, more generally, a substantial problem with the AER's reliance on benchmarking. For the reasons discussed in this Chapter, it is readily apparent that the AER's benchmarking has miscarried, and is entirely unreliable due to methodological and data errors. This means it is critical, before making any adjustment to the opex proposed by Ausgrid, to identify a specific inefficiency that needs to be corrected. That role cannot be substituted by the AER's benchmarking exercise.

[295] Attachment 1.16 - Jacobs - System Capex and Maintenance Prudency Assessment, p.2

[296] Attachment 1.16 - Jacobs - System Capex and Maintenance Prudency Assessment, p. 50

Ausgrid relies upon the statement[297] of the Chief Operating Officer - Trevor Armstrong - which identifies at a practical level the broad scope of necessary opex, and the likely impact of the substantial reduction of opex contained in the draft decision. The statement indicates how significantly the AER's approach is at odds with the national electricity objective.

Moreover, the AER has not given any proper consideration to the impact of its benchmarking-driven adjustments on other building block components. The adjustments contained in the draft decision would have a material impact on Ausgrid's credit rating, and the risk profile of its business, and would therefore require a material adjustment to the WACC (both equity and debt).

6.7 Addressing substantive issues raised in the AER's draft decision

In the sections above, we identified that the AER's draft decision relied significantly on its benchmarking results to reject our base year opex and to determine a substitute forecast opex. We outlined our serious concerns with the AER's approach in its decision making and the merits of its benchmarking results. In this section, we address other issues raised by the AER with respect to its assessment of our proposed forecast opex.

At the outset, the AER has assessed our forecast opex not by reference to the forecasting method and supporting information we have provided in our regulatory proposal. The AER has represented our forecast opex by reference to its base-step-trend approach. We note that:

- We do not use this base-step-trend approach or the formulaic approach set in the AER's guidelines and were not required to do so.
- As stated by the AEMC, the information we were required to provide to 'fit' within the AER's base-step-trend approach does not form part of our regulatory proposal.

In the sections below, we address the AER's reasons for its finding in relation Ausgrid's forecast opex, characterised using its base-step-trend approach/formula.

Response to AER's base year finding

The AER supported its decision to reject our base year opex and adjust it by an 'efficiency adjustment' based on its benchmarking result by reference to:

- Ausgrid's regulatory proposal – the AER stated our proposal is evidence that the base opex is inefficient.
- Review of labour and workforce practices.
- Comments made by the Chief Executive Officer.

Ausgrid's proposal as 'evidence' of inefficiency

The AER stated that it has examined Ausgrid's regulatory proposal and accompanying information including the submission on the AER's issue paper. The AER concluded that:

> *Evidence that Ausgrid has historically had some inefficient practices is evident from its regulatory proposal and subsequent submissions. For example, Ausgrid cites concerns with stranded labour due to the reduction in capex since the formation of Network NSW….. stranded costs are clear evidence of Ausgrid's inefficiency.*[298]

We have serious concerns about this misrepresentation made by the AER. In both our transitional proposal and initial proposal, we explained that one cannot forecast expenditure requirement for the forthcoming regulatory period without taking into consideration the anticipated operating environment and changing circumstances. A forecast based on the benchmarking of historical data that ignores anticipated circumstances will not reasonably reflect 'a realistic expectation of demand forecast and costs inputs' as required by the rules.

In our transitional proposal, we explained:

> *For the 2009-14 period the AER approved a significant capital investment program, amongst other things, to comply with licence conditions mandated by the NSW Government. These licence conditions were needed to address the potential adverse issues arising from under investment in the past with respect to security and reliability of supply. Our capex program was also aimed at replacing the aged and deteriorated assets on our network which, if not addressed, could have resulted in large scale reliability and safety incidents.*
>
> *The approved capex program for the current period was Ausgrid's biggest ever investment. It equalled a doubling of Ausgrid's previous works program and was required to be delivered in addition to our regular maintenance and other works programs.*

[297] Attachment 1.02 - Statement of Chief Operating Officer of Ausgrid (CONFIDENTIAL)

[298] AER draft decision, p. 7-18 and footnote 31 on the same page.

The delivery of this much needed investment in a short span of time was beyond Ausgrid's internal capacity to deliver. For this reason, we outsourced part of the work and entered into alliance contracts with three partners, Transmission Cable Alliance, Energised Alliance and Energy2U Alliance. These alliance partnerships were a prudent course of action that allowed Ausgrid to deliver the capital investment needed to keep the network safe and reliable whilst not committing to an unsustainable level of long-term resources. Looking forward to the next five years, we still have a need to invest to maintain the safety and reliability of our network, but the need for capacity capex has subsided. Furthermore, recognising the pricing pressures customers are facing and the reduced forecast demand, we have actively reviewed our strategies, policies and planning processes to find efficiencies in our capital works program. As a result, our forecast capex is about 37% ($2013/14) lower than that required for the current period.

The lower forecast capex program will not require as many resources as were needed to deliver the approved capex program of the current period. These resources were previously tasked with the delivery of the capital program and therefore their costs were fully funded by the capex allowed by the AER for the current period.[299] *(emphasis added)*

We reiterated this in our initial proposal where we stated:

Coupled with the significant reduction in the forecast investment program for the 2014-19 period, Ausgrid is facing a pool of excess resources and other stranded costs, despite the prudent action we undertook in outsourcing additional required resources through the alliance partners.[300]

We failed to understand how the 'stranded cost is clear evidence of inefficiency'. These 'stranded costs' (or more correctly, reallocated overheads) reflect a change in the amount of some fixed divisional and corporate overheads allocated to operating costs as a necessary consequence of the reduced capital expenditure program. This change in the amount of fixed divisional and corporate overheads reflects a change in the forecast expenditure program for the 2014-19 period being simply not as large as that approved for the 2009-14 period which reflect the drivers of the forthcoming period. We also reiterate that the transitional regulatory proposal and the initial proposal did not include stranded unproductive labour. These submissions only included the costs of exiting excess resources. This revised proposal includes further productivity improvements and cost savings, above those included in our initial proposal, noting the additional savings have more than offset the reallocated fixed divisional and corporate overhead costs from the reduced capital program. It should also be noted, this change is in accordance with Ausgrid's AER approved CAM. In our initial proposal, we noted that:

It is important to note that in this proposal Ausgrid has not sought any funding from customers for the costs of stranded resources.[301]

On the contrary, we consider such misrepresentation is an indication that the AER has not engaged with our regulatory proposal or our submission on the AER's issue paper. As noted in our submission to the AER's issue paper, discussion of the 2009-14 period must be framed within its proper context. Discussion around the 2009-14 period must be cognisant of:[302]

The environment and the circumstances of the DNSPs at the time of submitting the 2009-14 regulatory proposal. At that time, the NSW DNSPs needed to address the legacy of previous regulatory decisions that resulted in an under-investment in our network. We needed to make significant investments to reduce safety risks and improve reliability in a climate of significant demand growth and new licence conditions. We were also experiencing the impact of the global financial crisis at the time of the 2009-14 proposal.

This need was recognised by the AER at the time of making its distribution determination for the 2009-14 period. The AER stated that:[303]

Each business plans to significantly increase its capital investment over the next five years. The AER's analysis confirms the need for, and efficiency of, an increased investment allowance, cognisant that this increased investment will result in higher user charges. These price increases are, however, less than those estimated in the AER's draft decision of last year, largely because the return on capital has been reduced to reflect lower interest costs and weaker economic conditions.

The AER also asserted that simply because we recognise a need to have a lower efficient cost base compared to the prior periods (which is reflective of our anticipated circumstances and operating environments) is admission that our base year opex is inefficient. The AER stated that:

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[299] Ausgrid transitional proposal January 2014, p. 33

[300] Ausgrid regulatory proposal, May 2014, p. 59

[301] Ausgrid regulatory proposal, May 2014, p.59

[302] NSW DNSP's response to the AER's Issue Paper, 8 Ausgust 2014, p. 3

[303] AER, News Release 05/09, 30 April 2009. See also AER, EnergyAustralia distribution determination 2009/10 to 2013/14, 28 April 2009, p. ix to x.

> *Therefore, if we find that the base year expenditure is inefficient or in some other way unrepresentative of the expenditure needed to achieve the opex objectives in the forecast period, we adjust it. The NSW service providers do not appear to disagree with this because their regulatory proposals recognise a need to move towards a more efficient cost base*

Firstly, our regulatory proposal never stated that our base year opex was inefficient. To the contrary, we demonstrated that our base year opex is efficient having regard to the efficient opex allowance approved by the AER for the 2009-14 period and the incentive scheme applied by the AER to incentive us to improve our efficiency, consistent with the objective of the regulatory framework. Ausgrid's proposal did not 'agree' with the AER's contention that the base year opex is inefficient.

Our regulatory proposal appropriately recognises a need to have a lower opex requirement for the forthcoming regulatory period reflective of the underlying drivers and circumstances of the forthcoming regulatory period. These drivers are the catalyst for the need to have a lower efficient cost base, as compared to the previous period, which is only appropriate. Recognition of a need to have a lower efficient opex is recognition of the changing circumstances, environment and drivers; not a recognition that the prior period expenditure is inefficient.

Secondly, we submitted our initial regulatory proposal in May 2014. At the time, we could not have anticipated the results of the AER's assessment and its draft decision. Therefore, we could not possibly be in a position at the time to either 'agree' or 'disagree' with the AER's findings on our base year opex. We were required by the rules to explain the forecasting methods used to develop forecast opex as well as the key variables relied upon to derive the operating expenditure. We fulfilled this obligation by explaining the approach we undertook to forecast our opex requirements for the next period and the underlying drivers (i.e. key variables) of this period. Obviously, when a business is undergoing a transformation and the drivers of expenditure changed, the expenditure profile will change and respond correspondingly. The response could be an upward revision to an expenditure profile or a downward revision to an expenditure profile depending on the nature of the underlying drivers. It is erroneous to assert that because we recognise a need for a downward revision is an admission that past historic expenditure is inefficient.

Review of labour and workforce practices

In its draft decision, the AER determined that Ausgrid's labour costs are inefficient. As part of our revised proposal, we have provided additional evidence to address these claims and to support the forecast for the 2014-19 period. This additional evidence includes:

1) An independent report by the Arup Economics Team (Confidential Attachment 6.01) on the prudency of Ausgrid's labour management in the past and going forward.
2) A Strategic Delivery and Workforce Plan for 2015-19 (Attachment 5.05) which further articulates labour practices utilised by Ausgrid and supports the volume of labour built into Ausgrid's capex and opex forecasts.
3) Independent reports from CEG and K&L Gates.[304]

Arup Labour Analysis Report

The AER engaged Deloitte Access Economics to review Ausgrid's labour and workforce practices. From this review Deloitte concluded *"… that there was evidence that the approach to resourcing was not efficient or prudent."*[305] The AER concluded that Deloitte's findings are supporting evidence underpinning its 'efficiency adjustment' to Ausgrid's base year.[306]

In response to this finding, we engaged Arup to prepare an independent report to analyse Ausgrid's labour practices over an extensive period of time. In addition to this, Arup was asked to form an expert opinion as to whether our proposed expenditure for the 2014-19 period was prudent and responsible as our business responds to changing circumstances and underlying cost drivers. Arup has concluded that the labour practices that Ausgrid used from 2000-2014 were prudent and that Ausgrid's proposed response to a changing environment and cost drivers from 2015-19 is responsible when considering how similar businesses have also responded. In forming this opinion, Arup has engaged in a more detailed review of Ausgrid's labour practices than what has been exhibited by Deloitte.

In developing this report, we asked Arup to consider all potential drivers of labour costs over time as opposed to answering a selectively chosen subset of questions that the AER asked Deloitte to answer.[307] While Arup has considered a broader range of issues than Deloitte in coming to its conclusion, it has in turn answered through its analysis the same questions that Deloitte was asked and has come up with different conclusions to Deloitte based on its more thorough analysis.

Arup concluded that Ausgrid effectively developed a flexible workforce using a combination of methods such as the Memorandum of Understanding, the Alliances, labour hire and overtime to meet the significant increase in investment that the AER approved for

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[304] Attachments 6.02 (CEG: Labour unit cost – review of Deloitte report (CONFIDENTIAL)) and 6.03 (K&L Gates: Comparison and Analysis of Enterprise Bargaining Agreement for Distribution Networks (CONFIDENTIAL)) respectively.

[305] AER draft decision, p. 7-129

[306] AER draft decision, p. 7-33

[307] AER draft decision, p. 7-87

the 2009-14 regulatory period. Mechanisms such as the MOU and Alliance led to significant net savings associated with ongoing embedded labour costs. This reduction in embedded labour is demonstrated by the reduction in our workforce by 2014 to levels not seen since prior to 2009. This is in part recognition of Ausgrid meeting the 2007 licence conditions and changes in the growth environment which resulted in Ausgrid ramping up its workforce over the period 2009-2012 to meet in the investment plan approved by the AER for the 2009-14 regulatory period.

Furthermore, Arup examined a number of areas around labour management practices that have driven Ausgrid's labour costs in the past and will continue to influence labour costs. In relation to labour arrangements, Arup has found that Ausgrid has prudently approached EBA negotiations over a period of time utilising a range of negotiation strategies to reduce labour costs. This includes offsetting wage increases below industry increases since at least 2009 and in line with public sector increases since 2010. Moreover, in regards to the management of labour, Arup concluded that Ausgrid effectively utilised a mix of labour practices to reduce embedded labour costs and conservatively increased labour supply to meet greater demand. Arup states:

> *These strategies have not always been restricted to hiring of permanent internal labour resources through taking on new apprentices (the usual path of expanding its workforce) or by external recruitment (of skilled and qualified persons), when a positive gap has been identified. Other approaches which are evident have included:*
>
> - *Outsourcing such as:*
>   - *Use of contractors;*
>   - *Labour hire;*
>   - *The Alliance program; and*
>   - *Contracted services.*
> - *Insourcing such as:*
>   - *Redeployment between depots;*
>   - *Redeployment between divisions;*
>   - *Additional overtime;*
>   - *Competing in the external market place for design, construction and maintenance projects for other DNSPs.*
>
> *In periods when a negative gap has been identified, the approaches which have been adopted include:*
>
> - *Outsourcing such as:*
>   - *Reduction (or elimination) in the use of contractors;*
>   - *Reduction (or elimination) in the use of labour hire;*
>   - *Cessation of the use of Alliances; and*
>   - *Reduction (or elimination) in the use of contracted services.*
> - *Insourcing such as:*
>   - *Reduction (or elimination) of overtime;*
>   - *A cap on recruitment and/or workforce size;*
>   - *Reduction in taking on apprentices;*
>   - *Reliance on natural attrition;*
>   - *Voluntary redundancy; and*
>   - *Use of Mix & Match voluntary redundancy.*
>
> *Indeed during the last two regulatory periods, Ausgrid has adopted all of these strategies to address the size and composition of positive gaps (shortage in supply) and negative gaps (excesses in supply) which it has identified.*

Arup also concluded that the proposed totex expenditure by Ausgrid for the 2014-19 period demonstrates a prudent response to adapting to changing circumstances and cost drivers unlike the significant step down in totex proposed by the AER in its draft decision. Arup further elaborates on this, arguing that totex needs be considered when examining a business' response to a changing operating environment and costs drivers, as operating costs will naturally be incurred to facilitate this change.

Arup further argues that cost associated with redundancies to facilitate this change is an efficient response as it delivers a greater net present value of savings to the business and its customers over the long term. Arup concludes that the AER's rejection of restructuring costs in its Draft Determination fails to acknowledge that the AER facilitated an increase of labour to deliver greater investment in its previous determination. Arup also concludes that it unfairly penalises Ausgrid by not providing an allowance to recover the upfront costs associated with delivering savings to customers in the future. Arup argues that Ausgrid's proposed change to its operating environment reflects the legal and practical restrictions it faces as a business, unlike the changes proposed by the AER in its Draft Determination. Ultimately, it concludes that the proposed rate of reduction in headcount proposed by Ausgrid over the 2014-19 period, the costs of these reductions and the allocation of this costs reflects the actions of a responsible business adapting to a changes in its operating environment.

Due to the limited time we had to respond to complex and detailed enquiries by Deloitte, we feel that due process has not been given by the AER for a comprehensive report to be produced by its consultant. Deloitte claims to have reviewed a significant amount of documentation and to have held a number of meetings 'via video conference'. We do not believe that this level of engagement was adequate to produce a report which could definitively assess Ausgrid's labour practices as it has done. We also feel that a lack of clear direction was given by the AER and Deloitte as to what they were exactly trying to conclude as a result of these information requests and how these lines of enquiry would be weighted to form an opinion of the efficiency of Ausgrid's labour practices. As a result we feel that we were unable to fully inform Deloitte on issues prior to its claims being made. The Deloitte report also makes several broad comments in relation to multiple companies in NSW and the ACT which does not demonstrate that specific consideration of DNSP circumstances have been made on all issues. We view the AER's use of the content in this report to assess Ausgrid's labour practices as a 'serious' oversimplification on its behalf.

Strategic Delivery and Workforce Plans for 2015-19

To further support our labour estimates factored into our revised capex and opex forecasts, we have provided a strategic delivery and workforce plan for the 2014-19 period (Attachment 5.05). The strategic delivery plan assesses Ausgrid's ability to deliver its revised system capex and system maintenance program. This analysis then feeds into Ausgrid's wider strategic workforce plan which has been used to determine organisation wide oversupply or undersupply in labour.

These documents are a result of a routine workforce planning process that has progressively been implemented under the guidance of Networks NSW since June 2013, and builds on the workforce planning Ausgrid had established in the past. We have provided this plan as part of this revised proposal. The result of this workforce planning analysis has been used to support the legitimacy of our revised opex and capex forecasts. The details of this analysis can be found in Attachment5.05. Of note is the finding the Ausgrid will have sufficient workforce to deliver the revised expenditure programs.

Section 2 of the strategic delivery plan also further elaborates on flexible delivery strategies that Ausgrid has adopted over past years to deliver capital and maintenance programs. Many of these delivery strategies have been used and additional opportunities in areas such as blended delivery will be sought. These strategies included:

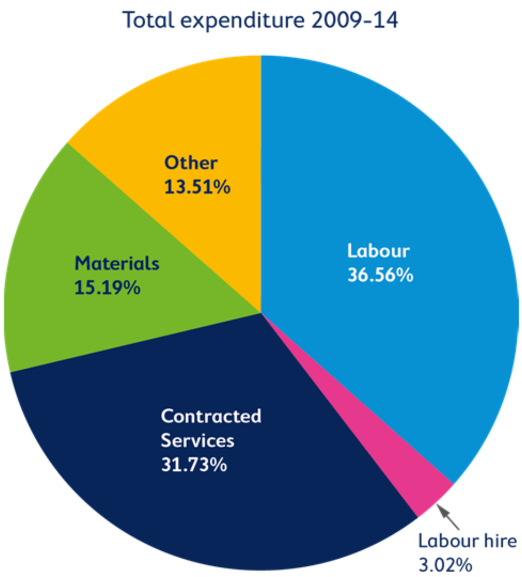
- Increase internal capacity through the targeted recruitment and training in critical skilled resource areas;
- Increase internal capacity and productivity through the targeted utilisation of overtime;
- Increase internal capacity through the phased withdrawal from the external and contestable works businesses;
- Improve labour productivity and investment planning efficiency through works coordination and technology;
- Increase external delivery of business as usual contract works via establishment of competitive panel arrangements;
- Form alliance partnerships to augment and facilitate the delivery of major projects; and
- Utilise a mixture of additional labour hire and contracted services to meet other peak overflow demands.

Figure 28 – Standard control services and public lighting overtime history ($million, nominal)

Arup's report and Ausgrid's strategic delivery plan demonstrated the flaws in Deloitte's analysis and consequently the AER's reliance on it to substantiate its decision that our base year opex is inefficient. Contrary to the AER's assertion, we consider Ausgrid has adopted prudent and effective management practices to deliver the capital and maintenance programs of the prior periods. Arup rejected the AER's assert that Ausgrid 'seem to have relied too heavily on hiring permanent internal labour resources rather than using temporary external contractors' as contended by the AER. It is also not correct for the AER to assert that 'it appears likely that the service providers' labour costs were impacted by a relatively inflexible workforce with limited ability to innovate or respond to changing circumstances'. Many of Ausgrid's capital and maintenance activities are fully or partially outsourced with the most significant externally sourced opex related activities include vegetation management, pole inspections, traffic management, aerial patrols, various IT functions, some fleet management and facilities management. In the past regulatory period, vegetation management costs have been around $35-40m per annum, with more than 80% of this externally sourced.

Significant externally sourced capex activities include all civil work, such as tunnelling, substation construction and site remediation, as well as cable laying. Figure 29 illustrates the extent of outsourcing that underpinned Ausgrid's expenditure. Ausgrid also sources a majority of its contracted services, materials and other costs via a competitive tender process.

Figure 29 – Composition of Ausgrid's total expenditure by cost categories[308] (%)



No evidence in Deloitte Report

The AER in their draft determination highlighted the analysis that Deloitte were undertaking as important in helping the AER decide whether expenditure in the base year was an appropriate starting point for forecasting total opex that will reasonably reflect the opex criteria for the 2014-19 period.[309] The AER has taken the views of its consultant on face value without interrogating whether the basis for Deloitte's conclusions is sound.

The importance that the AER has placed on the Deloitte report is deeply concerning given the significant flaws in Deloitte's analysis render their conclusions unreliable.

It is worth noting before considering the contents of the Deloitte report the way the AER has used the findings with regards to the AER's use of benchmarking.

The proposed base opex cuts were an output of the AER's benchmarking analysis, the flaws which are described above. The AER considered the findings of the Deloitte report as supporting evidence driving some of the scope of their proposed base opex cuts.[310]

The Deloitte report has a number of significant weaknesses. These weaknesses are fundamental enough to the nature of their analysis that the conclusions that Deloitte have reached cannot be supported.

In their report, Deloitte concluded that we had "labour costs entrenched in Enterprise Bargaining Agreements (EBAs) which are well above peer costs". [311]. This is despite their statement that "It is difficult to accurately identify differences in absolute wages costs between the DNSPs in different jurisdictions due to the use of different employee classifications and business structures."[312]

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[308] Other cost categories includes fleet management, tax, insurances etc. Source: Ausgrid's financial management system and Ausgrid's annual regulatory information notices.

[309] AER draft decision – Attachment 7: Operating expenditure, November 2014, p. 7-87

[310] AER draft decision – Attachment 7: Operating expenditure, November 2014, p. 7-90

Instead of attempting to assess remuneration in a way that reflects the combined components of labour costs, Deloitte instead cherry picked provisions from the EBAs. [313]

Drawing a conclusion about labour costs based on a limited range of factors would seem deeply flawed regardless of the factors considered. Given that none of those factors considered in the Deloitte report were the base rate of pay, it would seem to be impossible to draw any conclusions on relative labour cost through comparison of EBAs.

EBA's are the result of negotiations and trade-offs between different elements of remuneration and workplace practices would be expected. This fact is recognised by the AER in its draft determination[314] on labour forecasts, but is ignored by both Deloitte and the AER with respect to labour costs.

The AER has previously not sought to review the outcomes of EBA negotiations:

> *We note that the ongoing strength in wage increases in SP AusNet's recent EA outcomes appears to be in contrast to the expectation of easing in the overall competition for labour in Victoria over the 2014–17 regulatory control period. SP AusNet's EA outcomes, nevertheless, reflect the presumably free negotiations between SP AusNet, its employees and representative unions and we are not privy to these negotiations.*[315]

If Deloitte had undertaken some analysis of broader elements of remuneration they would have found that suggestions that we have higher labour costs than other DNSPs cannot be sustained.

One source of available evidence on labour costs is table 2.11 of the RIN, which required all DNSPs to identify labour costs per category of staff. Neither the Deloitte report nor the AER have commented on the data contained in this template although it was clearly developed to extract this type of information.

This available data suggests that the Deloitte report may contain an error of fact in asserting that our labour costs are higher than our peers. We reviewed the data in the RIN, and also re-checked the information we had provided to the AER in the RIN. Based on this analysis, our labour costs are in the low range of other DNSPs[316] in Australia, and lower than most of the businesses the AER included as "frontier" performers. While we remain cautious about the quality and comparability of the data provided in this template, we note that this evidence available to the AER does not suggest that our labour costs are the key driver of observed differences in benchmarking performance.

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[311] Deloitte, NSW Distribution Network Service Providers Labour Analysis, 17 November 2014, p. iv

[312] Deloitte, NSW Distribution Network Service Providers Labour Analysis, 17 November 2014, p. 31

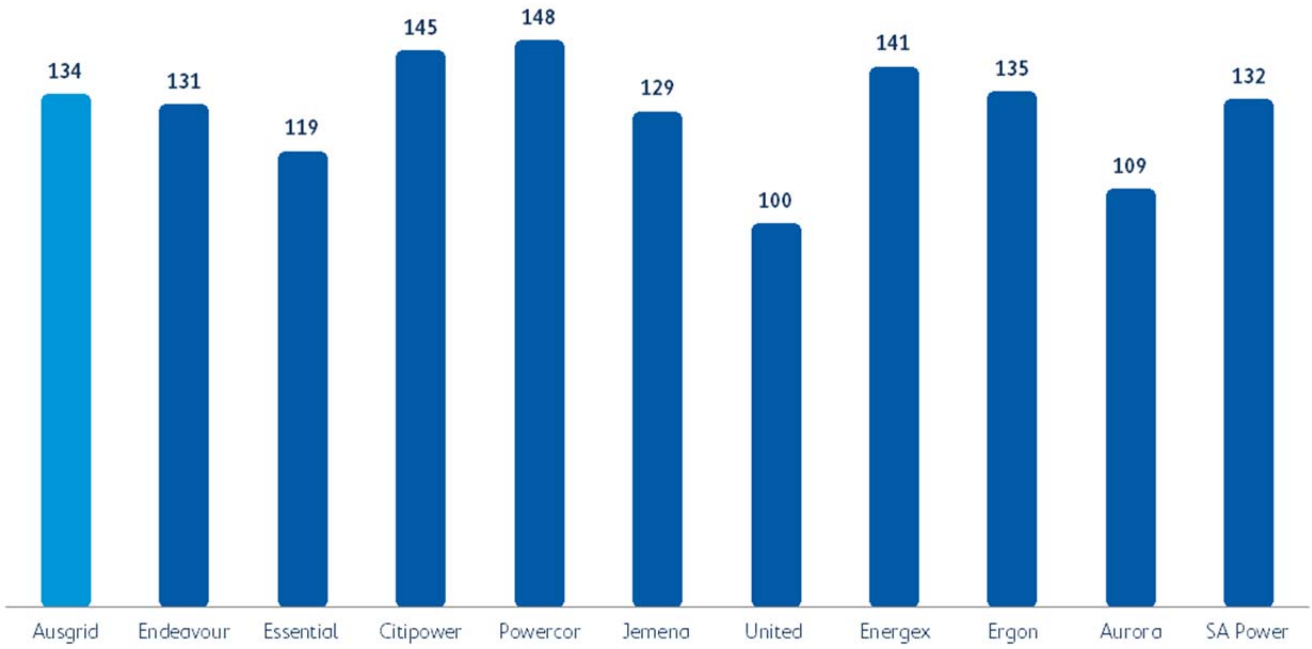
[313] As part of their analysis Deloitte have compared these provisions to the Industry Award. A comparison of this type reflects a deep misunderstanding of the nature of the Award compared to the EBA as such a comparison would suggest wrongly that EBAs should contain the provisions no higher than contained in the award.

[314] AER draft decision – Attachment 7: Operating expenditure, November 2014, p. 7-151

[315] AER final decision SP AusNet Transmission determination 2014-15 to 2016-17, p. 82.

[316] We note that we have made certain adjustments to information provided by Ergon and Aurora to rectify an apparent anomaly with decimal point which overstated its labour costs by a multiple of 10.

Figure 30 – Average labour cost per employee ($ '000)[317]



Note: Figure 30 was updated on 30 January 2015 to reflect the amended RIN data that Endeavour Energy provided to the AER on 20 January 2015 in Attachment 6.01 of its revised regulatory proposal.

NNSW engaged CEG to undertake analysis of labour costs compared to other DNSPs. The CEG report provided as confidential Attachment 6.02 found that our labour costs were comparable to our peers.

This outcome is despite the higher labour costs experienced more generally outside the energy industry in NSW when compared to Victoria, Queensland, Tasmania and South Australia.

Deloitte's analysis stems from an assumption that outsourcing is efficient in all circumstances, and therefore relative efficiencies can be attributed to differences in outsourcing rates. Deloitte does not provide evidence for this assumption

While the Victorian DNSPs outsource more than the NSW DNSPs the level of outsourcing is clearly not as disparate as presented by the numbers quoted by Deloitte, due to the majority of Victorian outsourcing being to related parties. A further aspect that appears to have been overlooked by Deloitte is a number of Victorian EBAs contain provisions that restrict outsourcing to where the engaged company applies wages and conditions which are no less favourable than those contained in the DNSPs EBA.

The more complete analysis by CEG directly refutes the Deloitte finding that our EBA provisions are more generous than those present in other states.

Deloitte also found that we have greater restrictions on workplace flexibility. They note they have not attempted to undertake a clause by clause comparison of EBA arrangements.[318] NNSW engaged K&L Gates to undertake a comparison of the EBAs for NSW DNSPs and DNSPs in other jurisdictions in relation to provisions that restrict workplace flexibility. K&L Gates, who are experienced industrial relations lawyers, found that the assertion that labour practices within our EBA are more restrictive than similar labour practices in other DNSPs in other jurisdiction cannot be sustained. We also note that, according to K&L Gates, Ausgrid's redudancy conditions are not dissimilar to others in the industry.

K&L Gates's report is provided as confidential Attachment 6.03.

[317] We note that SPAusNet have made information in template 2.11 confidential.

[318] Deloitte, NSW Distribution Network Service Providers Labour Analysis, 17 November 2014, p. 42

Again Deloitte seems to have cherry-picked provisions from within the EBAs to support its conclusions. As part of their analysis on all relevant provisions, K&L Gates analysed these provisions. Their findings, which contradict those of Deloitte, may be a reflection of their greater experience in industrial relations for electricity networks.

We consider that the Deloitte report finding that the NNSW businesses are high cost employers with inefficient work practices when compared to other DNSPs is without foundation.

Comments by the Chief Executive Officer

Both the AER and the Deloitte Access Economics have selectively quoted from an article written by CEO Vince Graham and published in the Australian newspaper on 20 August 2014 to support their conclusions on the efficiency and productivity of (DNSPs) workforce.

The success of the NSW Network Reform Program, commenced in July 2012, is clear evidence of the potential to progressively improve both the capital and operating efficiencies of Ausgrid. The continuation of that program is embedded in this revised proposal with committed labour productivity improvements of 6% p.a over the determination and capital expenditure program that incorporates continued progressive cost reductions over the next four years through changes to program scope, more efficient project design, improved labour utilisation and reduced unit costs. Together these deliver a program that is 20% lower than our original proposal by the end of the period.

What Mr Graham's public comments also included was an acknowledgment of the difficulty in rolling back legally binding terms and conditions of employment embedded in certified agreements under the Fair Work Act.

> *Removing or rolling back these conditions is challenging given the Fair Work Act. Progressively and safely contracting out the maintenance and capital activities of NSW Networks is one of the few means available to address these uncompetitive but legally binding union agreements.*

The legal reality is that certified enterprise agreements are a regulatory obligation on all employers determined by an Act of the Australian Parliament. The AER cannot simplistically conclude that obligations imposed by labour regulations and certified enterprise agreements can be unilaterally and retrospectively rescinded by their own economic regulation nor does NEL enable the AER to do so.

Mr Graham's article was a transparent acknowledgment that continuing labour reform was necessary and set a pathway to progressively achieve that reform.

What is required is real and sustainable improvement in labour and capital efficiency driven by determined leadership in the long term interests of customers.

During the 2009-14 period, Ausgrid had a growing business needed to address the under-investment of the period periods. This growth in expenditure was fully endorsed by the AER's 2009-14 determination. Ausgrid had implemented an effective workforce in that growing environment using apprentices, labour hire, overtime, outsourcing and increased permanent staff numbers.

These management practices enabled Ausgrid's delivery capability to expand rapidly. These management practices were prudent in the growth environment because they utilised resources that could be quickly turned 'on and off' as needed. Overtime, labour hire and outsourcing are relatively easy to turn off and we have done so as requirement subsided. This is evidenced in our capex and opex forecasts that formed part of our business plans since about 2011 when we realised the drivers for expenditure requirement has subsided. Compare to the use of overtime, labour hire and outsourcing, the permanent workforce is the hardest to shrink quickly without considerable costs.

For the 2014-19 period, capital investment needs are not forecasted to be as large as those required for the 2009-14 and this is reflected in the capital expenditure forecasts we have submitted to the AER. In this context, Ausgrid is not transitioning to an efficient level of costs; rather it is transforming the business to reflect the anticipated circumstances and needs of the future. This is a prudent course of action that any efficient business would undertake.

'When efficiency should take effect'

Our proposed forecast opex included voluntary redundancy costs to cater for the resources above requirements of the 2014-19 period. The AER rejected these costs on the basis that:[319]

- It is not required to have regard to the individual circumstances of Ausgrid as the result of the 2012 rule change.

[319] AER draft decision, p. 7-52 to 7-54, 7-73 to 7-74 and 7-90.

- to allow these redundancy costs is to impose 'inefficiencies on consumers rather than service providers' and that consumers should not be asked to bear these costs.

As previously outlined, the AER's analysis of the intended effect of the 2012 rule change is flawed and has consequently infected its decision in various aspects, particularly in this instance with respect to its reliance on this flawed analysis to reject Ausgrid's forecast voluntary redundancy costs. We explained in our proposal that these costs resulted from surplus resources of the prior period. These resources were legitimately needed to deliver the capex program that the AER approved. As surplus to requirements to the forthcoming period, we need to exit these resources which consequently give rise to the need for redundancy costs. This is in no way different to any other businesses, in any environment, that undergo the necessary transformation to respond to changing circumstances and drivers. This is a prudent course of action that necessitates the redundancy costs which will result in long term benefits to customers through a lower opex profile going forward. Furthermore, by not allowing a business to transform itself (hence implementation costs) will hinder the incentives to drive efficiencies when effective to do so.[320]

For the AER to disregard Ausgrid's circumstances in the forthcoming period is flawed and is contrary to the requirements of clause 6.5.6(c) of the rules (i.e. the opex criteria). It was clear from the pronouncement of the AEMC that the removal of the phrases ' in the circumstances' from the opex criteria does not obviate the need for the AER to have regard to the individual circumstances of Ausgrid.

Furthermore, the AER characterised these costs as costs to 'transition' Ausgrid from an inefficient opex level to an efficient opex level. As we explained above, this is an incorrect characterisation of our opex proposal, the circumstances and context of this opex forecast, particularly vis-à-vis the opex incurred in the prior period. The fact that Ausgrid included a voluntary redundancy costs in the total opex forecast is an appropriate recognition of the underlying driver to the forthcoming period. It is not a recognition that we are transitioning from an inefficient opex level to an efficient opex level. As explained in our forecasting method statement, in our transitional proposal and in our initial proposal, recognition and incorporating anticipated circumstances, environment and drivers of the forthcoming period is critical to a forecasting method and approach and is necessary if the resulting forecast opex is to be reasonably reflective of the opex criteria, namely, efficient costs, costs that a prudent operator would require and most importantly in this context a realistic expectation of demand forecast and cost inputs.

Additionally, we understand that the AER is posing this issue as one that is about who should bear the costs, the consumer or the 'shareholders'. We consider such view of the issue is not legitimate under the assessment framework of the rules that the AER is bound to give effect to. The rule is clear that the AER must accept a DNSP's forecast of required opex if the AER is satisfied that the forecast opex reasonably reflects the opex criteria. In the context of the voluntary redundancy costs, the central issue for the AER's assessment is whether Ausgrid's proposed voluntary redundancy costs reasonably reflect the costs that a prudent operator would need to achieve the opex objectives.

We consider that redundancy costs are legitimate costs that a prudent DNSP would require, particularly taking into account Ausgrid's circumstances, a factor that the AER need to have regard as clarified by the AEMC in the 2012 rule change. As the cost of hiring employees is a legitimate cost, so must the costs of exiting employees once their services are no longer required. This is also consistent with the revenue and pricing principle as allowing Ausgrid a reasonable opportunity to recover the efficient costs Ausgrid incurs in providing direct control services.

It would not be prudent for us not to have considered the existence of resources surplus to requirements for the next period and not have appropriate course of action to manage the removal of these excess resources.

Our position is supported by the expert evidence of Professor David Newbery who agrees that redundancy costs are legitimate costs. After considering alternative approaches to dealing with such costs, Professor Newbery stated that:

> *But either way, it would be unreasonable for the AER to expect instant movement to the efficient frontier with no attendant costs, of which redundancy payments are the most obvious.*[321]

Finally, the benefits resulting from the exiting of excess resources will be eventually enjoyed by consumers rather than the shareholders because the expected lower labour costs will accrue to consumers in subsequent regulatory periods in the form of lower opex requirements.

On the above basis, we do not accept the AER's decision on redundancy costs. As discussed further below, our revised forecast opex incorporates the latest information on our reform programs.

Ausgrid's response to the AER's 'rate of change'

'Rate of change' is a component of the AER's formulaic approach to assessing proposed forecast opex and determining a substituted amount. This rate of change has three elements, namely: price change, output change and productivity change. We address the AER's assessment below.

[320] Further discussion can be found in Attachment 1.07.

[321] Attachment 1.07 - David Newbery, Cambridge Economic Policy Associates: Expert report, Jan 2015, p. 20

Price change

Ausgrid accepts the AER's decision to use an average of Deloitte Access Economics and Independent Economics' forecasts for labour price. We have incorporated the AER's draft decision in the revised forecast opex. Consistent with accepted regulatory practice, these rates will be updated by the AER closer to the time of the final determination to reflect the latest available information.

Output change

The AER's output change is the same output change measures and weightings as used in Economic Insight's economic benchmarking report. We have outlined our concerns about the AER's benchmarking techniques and results above.

Productivity

The AER has applied a productivity factor of zero when assessing the forecast of opex from the base year. We have reviewed the AER’s decision to assess whether we need to revise our proposal in response to the AER’s decision.

Our view is that our forecast method had already captured productivity growth through our efficiency programs. We note that our regulatory proposal incorporated efficiencies in the 2014-19 program related to our internal and Networks NSW programs. To the extent that productivity had been captured at a granular level of detail we consider that there is no need to revise our forecasting method to capture a general productivity dividend.

We consider that the AER’s decision to mechanically include a productivity dividend raises deeper concerns with the manner in which it has assessed our proposal. Our view is that the AER should engage with the information provided in our proposal to assess whether our proposal for 2014-19 represented the efficient costs of achieving the opex objectives.

Further, in its draft determination the AER has not taken into account the time and resources it takes to deliver transformation in the NSW DNSPs.

It takes time to deliver change in the NSW electricity distribution businesses, because it must be done:

- ***Safely & legally*** - for our employees and for the public, because of the direct inherent dangers of electricity and its operation, and the secondary risks related to our infrastructure, such as bushfire prevention. Consistent with our operating licence conditions legislated by the NSW parliament, and the Fair Work Act, the Federal legislation that governs the processes surrounding the Industrial Relations framework under which we must operate our workforce.
- ***Affordably*** - in a way that minimises the cost of change for the electricity consumers of NSW. Irrespective of whether that cost is borne by our shareholders or our customers, we aim to minimise the cost of change such as to deliver the most efficient outcome for society.
- ***Reliably*** - as an essential service, we must ensure we are managing the distribution network sustainably, both for now and in the years ahead. This includes having regard for both the technical operation of our assets and the impacts on our workforce given the rights under the Fair Work Act our workforce has for protected industrial action.

Ausgrid will fulfil its obligations to its customers, the people of NSW, in a way consistent with these principles. It is possible to reduce costs faster by ignoring these principles, however history has proven that reducing costs faster can have consequences, be it in terms of public safety (see Black Saturday class action settlement of $494m), extended industrial action (see Citipower’s 1997 fifteen week industrial dispute), or simply costing more than it should.

It must also be recognised that the assets contained in the electricity network are long lived in nature, and inherently complex. The effective management of these assets must therefore take into account their duration when looking to implement change, and transition to a new operating environment.

Attachment 6.04 sets out the process Ausgrid must undertake as it continues to transform to a new capital and maintenance program over the next four years and the exogenous factors that constrain the speed at which transformation can be achieved. Again, the AER has given no regard to the reality of this operating environment in dismissing all restructuring costs.

Immediate adjustment to the AER's forecast opex not appropriate

We consider that the AER should accept our revised forecast opex. However, if the AER was to determine that significant reductions in our forecast opex of the size contemplated by the AER's draft determination should be implemented, then we consider that the AER is required to implement it, and provide a forecast opex, that provides for a realistic forecast of Ausgrid's actual costs while incentivising efficiency reductions over time in a realistic manner.

The AER must determine a forecast opex that reasonably reflects the operating expenditure criteria having regard to the operating expenditure factors under clause 6.12.1(4). The operating expenditure criteria that must be reasonably reflected are:

- the efficient costs of achieving the operating expenditure objectives;
- the costs that a prudent operator would require to achieve the operating expenditure objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

The operating expenditure criteria and the requirement for the AER to consider the individual circumstances and actual costs of Ausgrid are discussed above.

Given the inherent requirements on Ausgrid to supply electricity safely, legally and reliably, any reduction in opex must be carefully planned and managed. This careful management and planning has been reflected in the efficiency programs that Ausgrid and the broader Networks NSW's group of businesses have adopted in the last regulatory control period. These efficiency programs are delivering substantial savings that are reflected in this revised proposal.

Ausgrid is currently subject to the allowed revenue (and opex) under the transitional determination and, prior to that was subject to the allowed revenue (and forecast opex) under the regulatory determination for the 2009-14 regulatory control period. Any sudden reduction in allowed revenue caused by a reduction in forecast opex such as that contemplated by the AER's draft determination has the potential to jeopardize the safety and reliability of Ausgrid's network as described above. A prudent operator would not take this risk given the potential consequences as explained in the statement by the Chief Operating Officer of Ausgrid. However, it would also be inconsistent with both the operating expenditure criteria and the national electricity objective for the prudent operator for shareholders to bear the cost of the significant reduction in forecast opex because doing so may cause significant financiability risks to Ausgrid, which would reduce its viability and the incentives and ability to invest in its network.

To avoid these risks, the operating expenditure criteria require the AER to determine forecast opex that (amongst other things) reasonably reflects the realistic cost inputs to achieve the operating expenditure objectives. It is not realistic for Ausgrid to instantaneously reduce many of its costs, such as its labour costs under its EBA, because it is legally prevented from doing so. These costs have been permitted by the AER and incurred by Ausgrid through the last regulatory control period. Any adjustment to these costs to incentivise efficiency must also reflect the time that it would realistically take Ausgrid to implement them.

Ausgrid's response to the AER's assessment of maintenance opex

As we have noted above, the AER has undertaken significant benchmarking studies to attempt to show that Ausgrid is inefficient against what the AER considers to be the 'efficient frontier' DNSPs. We outlined below our concerns with the AER's use of benchmarking in the context of maintenance expenditure.

Table A.4 (page 7-32 of Attachment 7) of the AER's draft determination considers Ausgrid's costs are high compared to the 'efficient frontier' DNSPs. As noted above, we have concerns with the AER's assessment approach and the merits of its benchmarking result. There is no or very limited consideration for the individual network and operating risks of each service provider nor is there any indication of the AER assessing the underlying costs and cost drivers that support our opex proposal. In essence, the AER's has taken the view that "the cheapest is the best".

While the AER claims to have made appropriate adjustments to allow for benchmarking across DNSP's, Ausgrid considers that the AER has not given appropriate consideration to the individual circumstances of its network. The AER has also failed to give due consideration to network risk and Ausgrid's risk management methodologies. This is reflective in the AER's consideration of the frontier DNSP's being those that incur the least cost. Ausgrid uses Reliability Centred Maintenance (RCM) to determine the most appropriate asset maintenance cycles. This methodology utilises real asset performance data to determine the most appropriate balance between preventative maintenance cost and risk. The AER's pure benchmarking techniques and reliance on costs have not taken into consideration this balance.

Ausgrid understands that at least one of the DNSPs that we are being compared to is proposing additional opex requirements due to increasing failure rates and a transition to maintenance strategies. These appear to more closely align to those which Ausgrid undertakes and therefore past opex expenditure levels will not reflect the required level of opex they require in the future. Ausgrid also notes the recent liability settlement of $494 million (including $380 million against SP Ausnet) for the Killmore East fire which killed 117 people and destroyed more than 1,000 houses, and that the Royal Commission into the cause of those bushfires identified systemic network maintenance shortcomings which have to be addressed and will likely increase opex requirements for a number of Victorian DNSPs in the future. The figures below show the increases in OPEX that other DNSP's that were are being compared to have undergone since 2006 and note that they have both almost doubled during that period. This lack of consideration of risk and pure reliance on cost benchmarking will place the long term sustainability of the network at risk and increase the safety exposure of the network, both to Ausgrid staff and the general public.

Figure 31 – SA Power Network's 'network maintenance opex', 2006-2013 (million, $2013/14)[322]

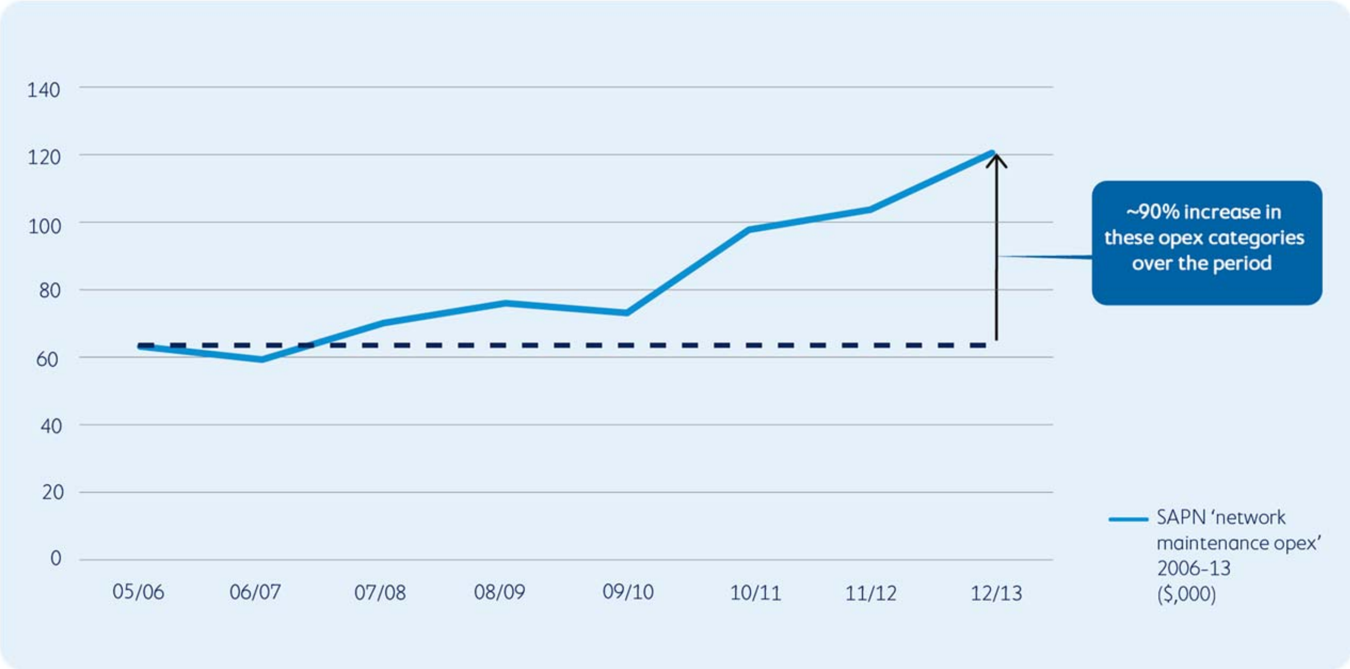
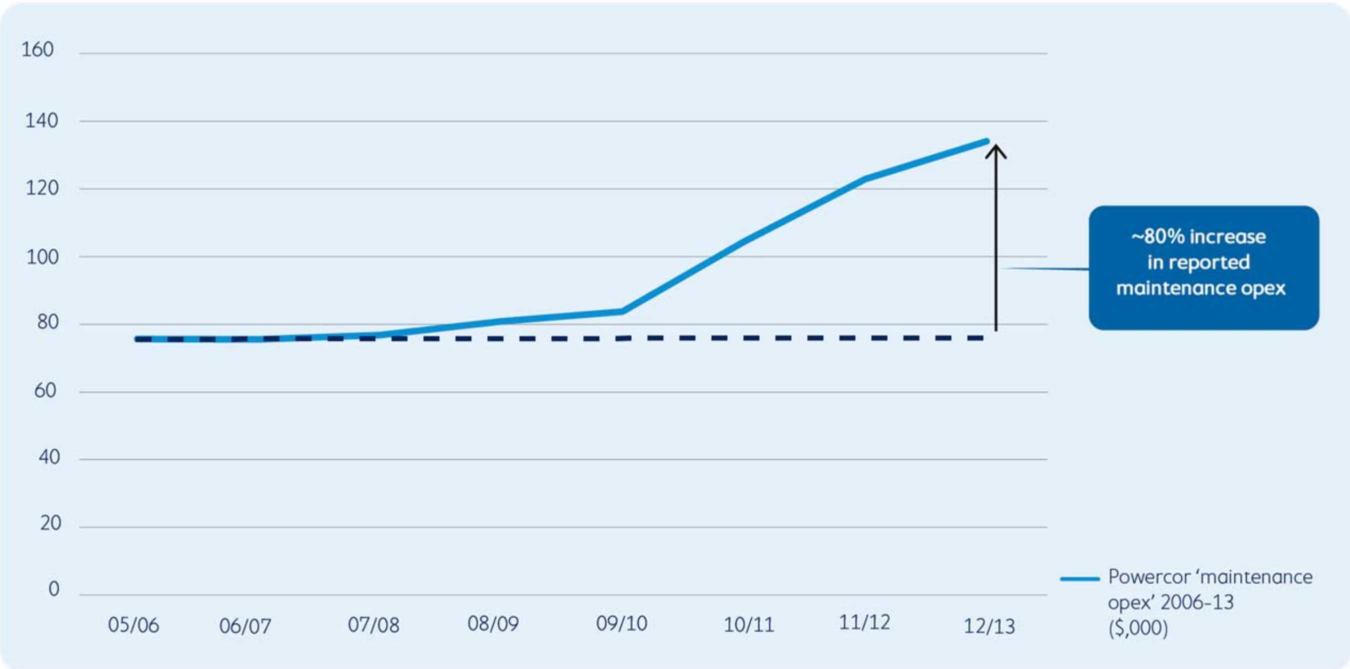


Figure 32 – Powercor 'maintenance opex', 2006-2013 (million, $2013/14)[323]



[322] SA Power Networks' economic benchmarking RIN did not include the same categories as Powercor reported. This chart therefore uses the information SA Power Networks submitted to the AER as part of its latest regulatory proposal in Attachment 20.73 'SA Power Networks: Capital and Operating historical expenditure, October 2014, p. 8.

[323] This is derived from the sum of 3 relevant Benchmarking RIN categories DOPEX0118A 'Routine', DOPEX119A 'Condition based', DOPEX120A 'Emergency'

Within Table A.4, the AER distinguishes between our underlying labour costs and differing sub-categories of these labour costs including maintenance, emergency response and vegetation management. The apparent "high" and "very high" relative costs for both maintenance and vegetation management is explored further below.

Use of benchmarking for maintenance opex

The AER has considered our maintenance expenditure to be high against what it considers to be the frontier (lowest cost) DNSPs. The AER has used circuit length as a substitute for comparing maintenance costs. In Figure A.16 (page 7-83) the AER has coupled this with customer density in benchmarking across the National Electricity Market (NEM). Customer density varies significantly across our network and therefore using a high level comparison of customer density against circuit length which is then used to determine our forecast level of opex is inherently flawed. The DNSPs that Ausgrid are compared against are predominantly CBD/Urban area DNSPs or Rural DNSPs whereas Ausgrid's network can be characterised as all of these, i.e. CBD/urban and rural.

Ausgrid has a significant number of distribution, zone and sub-transmission substations with a high population of maintenance intensive assets. These include oil filled switchgear and instrument transformers. While Ausgrid has been moving to newer and less maintenance intensive technologies, significant volumes of older technology assets still remain in service on our network. Customer density is not sufficient to give an accurate account of these assets and their maintenance intensive nature.

Our distribution substations include indoor, chamber and outdoor enclosures, underground, kiosk and pole type substations. Compared to kiosk and pole type substations, the other types of substations are relatively maintenance intensive. For example, in the Sydney CBD Ausgrid has more than 500 distribution substations with an average age of 36.6 years. These substations are typically underground substations located in commercial premises but may also be located on upper levels of those premises or under roadways within the CBD. These substations have aged and maintenance intensive assets, typically containing asbestos, and are classed as confined spaces, requiring rescue personnel standing by whenever the substation is accessed. Additionally, due to the CBD being supplied by a 'triplex' network, significant switching is required to allow for maintenance to take place. The AER has not given due consideration to these differences in its benchmarking against typically urban or rural DNSP's and appears to have arbitrarily selected adjustment percentages at a global level.

Additionally the AER has used "Weighted Average Remaining Life" (WARL) to disregard the differences in age profiles across NSP's. The AER concludes that the NSW DNSP's networks are 'relatively young'. Chapter 5 (capex) highlights fundamental flaws with WARL and its use in this context. There are two main issues with the WARL used by the AER:

1. WARL misrepresents the true average age of Ausgrid's network. The AER has Ausgrid's age profile information and could have used actual ages instead of WARL.
2. WARL assumes a flat age profile across the asset base and does not accurately account for the "double hump" effect seem in Ausgrid's age profile as a result of boom-bust investment cycles. Averages therefore not provide the most appropriate representation of asset age.

On the above basis, we consider that the benchmarking undertaken by the AER is not appropriate to either assess Ausgrid's maintenance requirements or to determine a substitute amount.

Vegetation Management

In undertaking its review of our vegetation management, the AER chose to include details of Essential Energy's draft determination (for example, page 7-90 to page 7-102), rather than providing an explanation of its findings on Ausgrid's proposed vegetation management opex. It therefore appears unclear to us the extent to which, if any, the AER has considered our proposal on vegetation management, detailed in Attachment 6.03 'System maintenance opex' of our initial proposal.

Rather than considering our proposal, the AER relied soley on its benchmarking techniquies and results. To allow for benchmarking of vegetation management, the AER has used 'route length' to weight costs across DNSPs. The AER requested we provide 'maintenance span' information as part of the regulatory information notice (RIN). In its draft determination, the AER have stated their preference for 'span length' over 'route length' in undertaking vegetation benchmarking. However, due to the different assumptions applied by the DNSPs the AER has decided to revert to using route length. The difference in the assumptions applied by each DNSP to maintenance span is reflective of the immaturity of the RIN data, which the AER used for its benchmarking analysis. Additionally the AER in identifying their preference for "span length" has conceded the inaccuracies in the use of 'route length'.

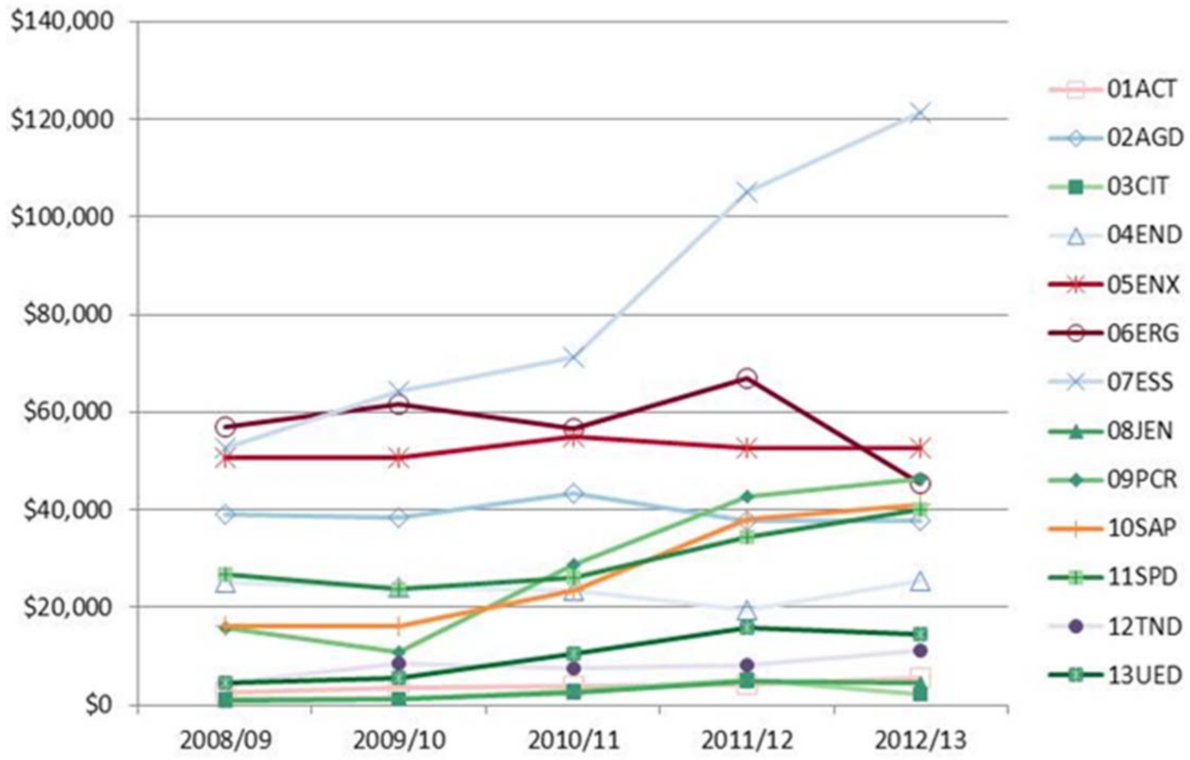
Ausgrid had provided the AER with 'route length' information in its RIN. Despite already possessing this information which was sourced from Ausgrid's GIS, and relying on the information we provided, the AER instead decided to calculate 'route length'. This calculation is grossly inaccurate and provides further doubt to the AER's benchmarking process utilising RIN data.

Despite these errors of fact we do not believe either metric provides an appropriate method for weighting vegetation costs. Benchmarking by this simplistic method does not take into consideration vegetation types, tree density, rain fall patterns and council and environmental group pressures. Additionally, vegetation responsibility is shared between Victorian councils and the DNSPs. These differences lead to large variations in vegetation costs across all DNSPs and should be considered when verifying the validity of benchmarking. The large assumptions and generalisations required in order to perform this benchmarking supports the use of bottom-up forecasting for vegetation management over top-down benchmarking.

On page 7-93 of the draft determination, the AER has used Figure A.19 to highlight the step change in Essential Energy's vegetation management costs since 2009. The AER has also stated that some of the other service providers have the same trend. As can be seen from figure A.19 of the AER's draft determination, Ausgrid's trend has been fairly consistent over the period from 2009.

Figure 33 – Total vegetation costs extracted from draft determination

Figure A.19 Total vegetation management costs 2009 to 2013 ($'000, 2014)



Source: Category analysis RIN data

Despite Ausgrid's consistent profile, the AER has included this figure and the qualitative statement of "other" service providers in its draft response. This appears to be a generalisation that is not reflective of Ausgrid's performance.

The inclusion of Essential Energy's draft determination and large generalisations reflect the AER's lack of consideration for our initial proposal. Our expenditure profile supports the appropriateness of its vegetation management being appropriate for the long term interests of consumers.

Operating Environment Adjustments

The AER have provided all NSW DNSPs with a 10% adjustment due to the differences in operating environment factors. Table A.17 on page 7-103 summaries three key areas where adjustments were made. This is shown below.

Figure 34 – Extract from AER draft determination - Attachment 7, Table A.17 - Summary of material operating environment adjustments

Table A.17 Summary of material operating environment adjustments

Service provider	Subtransmission adjustment	OH&S regulations	Bushfire regulations	Total
Ausgrid	5.5%	0.5%	-2.4%	3.6%
Endeavour	5.0%	0.5%	-2.4%	3.1%
Essential	2.5%	0.5%	-2.4%	0.6%

Source: AER analysis.

The 10% adjustment includes the factors presented in Table A.17 as well as the summation of additional factors the AER considers on their own to be immaterial. These include:

- Building regulations
- Corrosive environments
- Environmental regulations
- Grounding conditions
- Natural disasters
- Planning regulations
- Proportion of 11kV and 22kV lines
- Proportion of hardwood poles
- Shape factors
- Skills required by different service providers
- Topography
- Traffic management

Including all 15 different factors identified by the AER, it has arrived at a consistent (and subjective) 10% adjustment for all three NSW DNSPs. This is despite the considerable network differences across NSW DNSPs. This blanket adjustment is an indication that the AER has not given due consideration to these factors and how they apply directly to Ausgrid's network.

The 5.5% adjustment provided for Ausgrid's sub-transmission network appears to grossly understate the size of Ausgrid's sub-transmission network. Page 48 – 49 of Economics Insight Report 'Economic Benchmarking of NSW and ACT DNSP Opex' supports the need for an upward adjustment against the Victorian and South Australian DNSPs. It confirms the AER's recommendation that sub-transmission lines over 66kV are likely to have opex requirements per kilometre that are around twice as high as other DNSPs. It concludes that an appropriate adjustment may be formed by considering the percentage of total line length between the NSW DNSPs and the weighted average benchmark for Victorian and South Australian DNSPs.

These adjustments should also consider Ausgrid's sub-transmission equipment such as 132kV switchgear, instrument transformers, large MVA power transformers and other associated equipment such as complex secondary systems. The AER has excluded these assets despite this information being readily available in each DNSP's RIN submission.

Furthermore, all NSW DNSPs have a mix of 33kV, 66kV and 132kV circuits and equipment. Covering all three voltages places upward pressure on maintenance costs as a result of greater asset diversity. From the AER's own benchmarking data, the Victorian and South Australian DNSP's have no 132kV network.

The figures below show the difference in the sub-transmission networks across DNSP's using 2014 RIN data. These figures highlight the differences in circuit length as well as the spread across all three sub-transmission voltages.

Figure 35 – Sub-transmission voltage split (by circuit length)

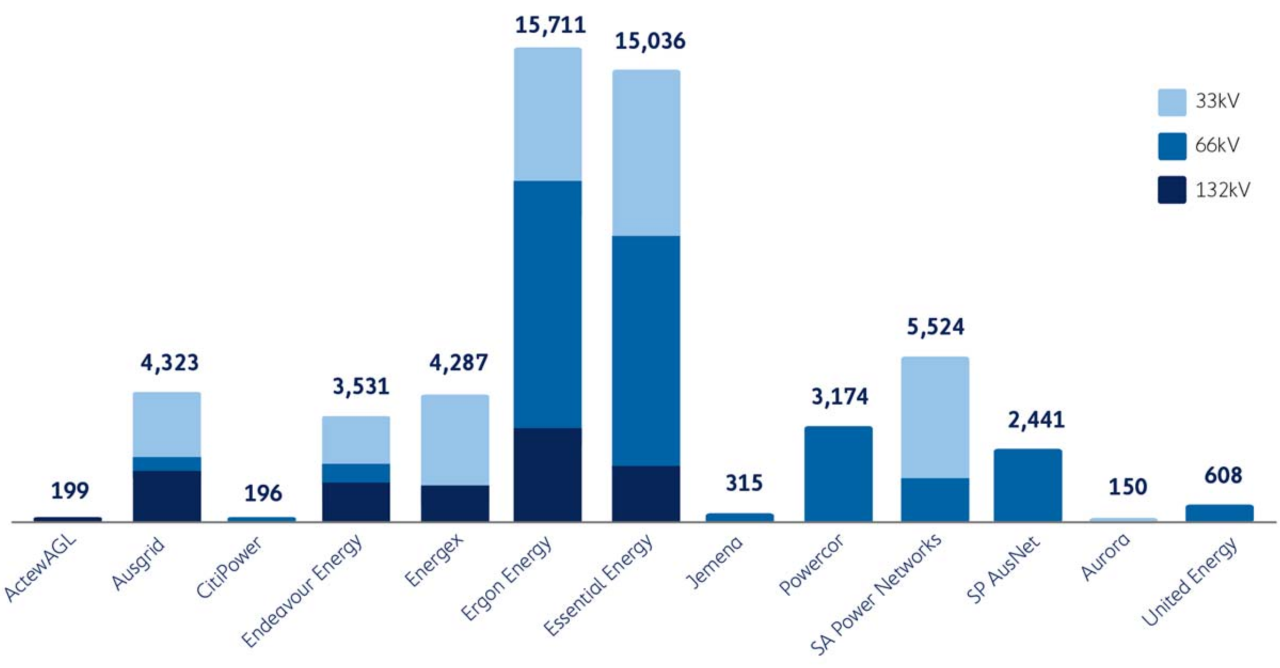
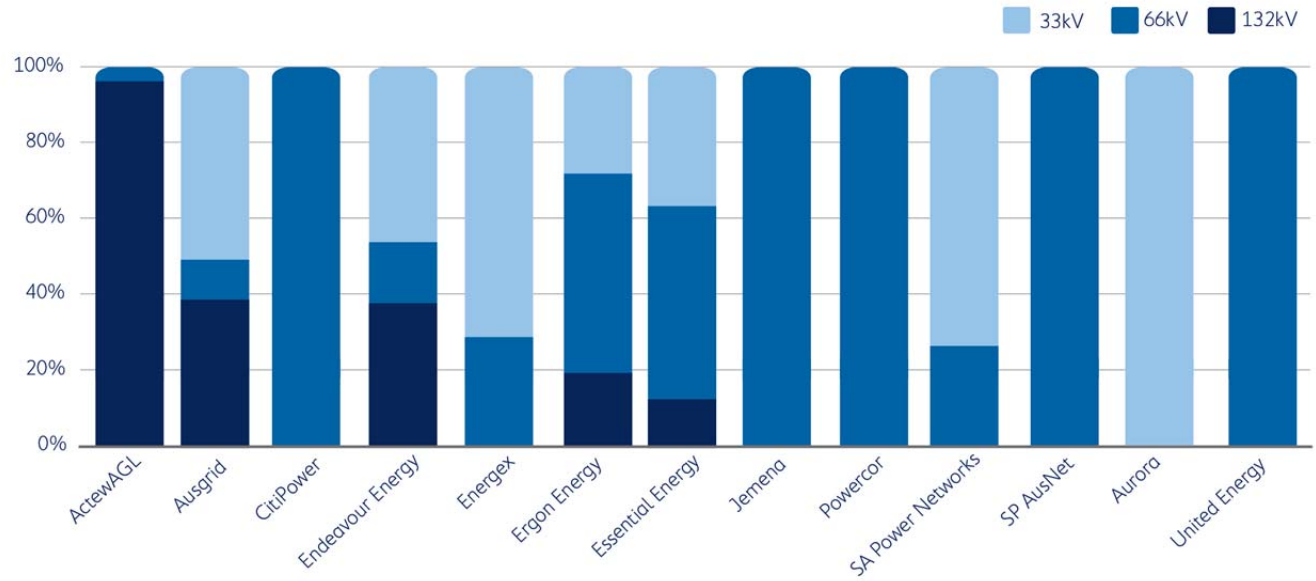


Figure 36 – Sub-transmission voltage split (by % of circuit length)



It is not apparent that the AER has taken into account these considerable differences when determining an appropriate operating environment adjustment for our sub-transmission network.

In discounting the need for an operating factor adjustment for customer density, the AER has acknowledged that the following factors, which it correlates to customer density, will impact network opex:

- Asset exposure
- Asset numbers
- Travel times
- Traffic management
- Asset complexity
- Proximity to third party assets
- Proportion of overhead and underground
- Topographical conditions

The AER has noted that customer density in itself does not drive cost. The AER's basis for discounting customer density is that customer numbers, line length and demand used to calculate MTFP will account for customer density. We were unable to determine how MTFP could with any accuracy account for the correlating factors listed above. The AER to some extent has acknowledged this in considering "topography" and "traffic management" as separate factors as shown previously.

The AER has used Table A.18 to show whether urban or rural networks benefit from the customer density factors. Ausgrid's network is a mix of both urban and rural networks and it is not clear to us how the AER has taken this unique characteristics of our network into consideration.

Private poles inspection and asbestos management

We had proposed to increase its maintenance program to address emerging asbestos exposure concerns and private mains risks. The AER on advice from the EMRF and Oakley Greenwood have rejected this, stating that since our obligations have not changed from last period, there is no justified need for a step change.

This position further enforces the AER's lack of consideration to network risk including and in particular WH&S risk. While NSW NSP's obligations have not changed, a number of incidents over the period have led to a greater focus on the risks of private networks and asbestos exposure. The tolerability for these issues across the community and the industry results has resulted in a greater need to ensure these risks are managed to an acceptable level.

This is further supported by the Victorian Bushfire Royal Commission. The Victoria bushfires highlighted the importance of incorporating emerging risks into a DNSPs opex and capex plans. In carrying out its due diligence, Ausgrid is relying on lead indicators to ensure it addresses its obligations in providing a safe network to its customers and staff.

While Ausgrid acknowledges that its obligations have not changed, its risk profile has, and consequently additonal opex is required to address these issues. We explained in our initial proposal that we are at risk of breaching our obligations and an inspection program is necessayr to address this risk.

The AER has concluded that Ausgrid could either:

1. Trade-off opex between opex categories
2. Reprioritise its opex budget

Ausgrid agrees in principle with the options outlined by the AER. However, Ausgrid's bottom-up approach to maintenance forecasting utilising RCM has already provided a balanced trade-off between risk and cost. As such, its system opex forecast is optimised to an appropriate level. Increased risk from asbestos and private mains does not result in a decrease in risk in other categories. Ausgrid's risk exposure has increased and as such it requires additional opex to address these risks.

Opex forecasting method assessment

The AER have criticised Ausgrid's methodology for forecasting opex on the basis that we did not select a single forecasting methodology (despite the fact that we submitted our forecasting method statement in November 2013 and again outlined these methods in our transitional proposal and initital proposal). The AER has quoted Frontier Economics from a previous determination, where it was their assessment that it would be inappropriate for the AER to review each component of controllable opex individually to see whether it conformed to the same pattern as overall controllable opex. The AER then stated that this would be considered 'cherry-picking' and would result in in aggregate controllable opex being systematically and inefficiently over-forecast.

This quote by Frontier Economics does not state that the use of different forecasting methodologies where appropriate is not justified. It concludes that a forecasting methodology should not 'cherry-pick' to attempt to conform to the same pattern as overall controllable opex. In applying the appropriate forecasting methodology to the appropriate opex category, Ausgrid has not undertaken what Frontier Economics has referred to in a previous determination process.

In fact in applying these different approaches Ausgrid has ensured that it has presented the most accurate information possible.

In rejecting the use of different methods the AER has compared the outcomes of our methods against their own. Ausgrid has used 'base year – variation by volume' to determine our preventative maintenance program. The AER have compared this to their 'base year' method. They conclude that Ausgrid's method produces higher forecast than their own ($19 million over the period).

They then compared Ausgrid's 'base year historical averaging' against their 'base year' method in forecasting nature induced breakdowns. The AER concluded that Ausgrid's method produced a lower forecast then their own.

The AER have used these differences to criticise Ausgrid's varying methods for mainteannce forecasting. These criticisms highlight a lack of understanding of the cost categories and their use. In order to explain these better the AER should consider the following maintenance categories:

- ***Predictable maintenance***: This includes planned maintenance activities such as inspections (preventative maintenance). Ausgrid's RCM methodology allows for annual maintenance volumes to be calculated based on known inspection cycles. This methodology combines a top-down 'base year' method and adjusts for any annual variation to volumes. 'Base year variation by volume' is the most appropriate forecasting method for this type of maintenance as it is more closely aligned with what maintenance we will actually do. For example, Ausgrid uses actual future volumes to vary its pole inspection forecast year on year. While we undertake leveling to apprioriately spread maintenance across years, there will always be some degree of variation year on year, based on the most efficient delivery of the program. Using 'base year variation by volume' allows us to account for these variations. That being said, given our leveling approach, the variation by volume is minimal against Ausgrid's 'base year' method. This is reflected by our reasonably flat year on year forecast profile.

- ***Semi-predictable maintenance***: This includes corrective and breakdown maintenance (repairs and restoration). Asset condition is based on a diverse range of factors making asset wear-out difficult to predict. Additionally the consequences and associated costs differ for each failure. However, using the most recent information on asset condition can give a close approximation of the current condition of network assets. As such, 'base year' forecasting from a single year is the most appropriate method for forecasting corrective and breakdown maintenance activities. For example, repair work is based on the results of our inspections. The base year gives us a reasonable estimate of the expected repair work required to address failures.

- ***Unpredictable maintenance***: This would include maintenance activities that Ausgrid is unable to predict. For example, it would be difficult for Ausgrid to predict when a car will hit a pole or lightning strike would hit and damage electrical equipment. Nature induced failures such as these fall into this category. Using a 'base year' method for unpredictable maintenance may overstate or understate expenditure depending on whether in a single year an unusual high or low amount of nature induced incidents has occurred. Using 'base year historical averaging' is a more appropriate method for forecasting unpredictable maintenance.

By viewing maintenance activities in these three categories we can see the reasonableness of our methodology. The level of predictability supports the most approriate forecasting method. Where possible and predictable, Ausgrid has utilised a bottom-up approach supported by its RCM process. It should also be noted that a change in maintenance or replacement strategy will have an impact on these categories.

The AER's reliance on the use of trends with a single overly simplified method is not the most appropriate means of forecasting system opex and does not comply with the obligations imposed on it to fully assess our proposal, taking into full consideration of the opex criteria and factors. We believe our approach is reasonable and built on asset management best practice. The AER has not demonstrated that our approach as unreasonable as is required under the opex crtieria. As such we rejects the AER's criticisms and consider that the AER should refer to our initial proposal.

Ausgrid's response to AER's assessment of 'step change'

Loss of synergy costs

The AER rejected Ausgrid's loss of synergy costs because it considered:

- it is satisfied that such costs is already provided for in the efficient base year opex that it determined using benchmarking. In addition it noted that none of the Victorian and South Australian distribution network service provide retail services.
- this costs does not fit within its own definition of a 'step change' i.e. a new regulatory obligation or a capex/opex trade off.
- It has changed its view on these costs since its 2009-14 distribution determination for Ausgrid in which it recognised that these costs are valid costs that should be passed through to customers.

We do not agree with the above reasons for the AER's decision to reject these costs and have therefore not revised our proposal to incorporate this decision. Our concerns with the AER's decision are:

- The AER cannot simply 'assume away' the nature and existence of these costs by relying on generalisation that 'an efficient base level of opex already provides sufficient funding for a prudent service provider to efficiently deliver standard control distribution services in the 2014-19 period'. This generalisation is particularly troubling considering the significant concerns we have with the merits of the AER's benchmarking results; on which the AER appeared to have based this generalisation that the AER's substituted base year opex will be sufficient for Ausgrid to achieve the opex objectives.
- We failed to understand the relevance of the fact that the Victorian and South Australian business do not have retail businesses. We consider that AER needs to have regard to the individual circumstances of Ausgrid, as it required to do, rather than relying on a simple basis that simply because the Victorian and South Australia businesses do not have retail services and Ausgrid does (or did) meant that these costs are therefore inefficient.
- The above two points again illustrates the extent to which the AER relied on deterministic benchmarking as the 'be all and end all' technique and basis for rejecting legitimate costs what Ausgrid would need incur in providing standard control services in the next period.
- the AER stated that it has now changed its view on the recovery of these costs. The AER stated that 'our views on what we consider should be a nominated pass through event has changed since our determination for Ausgrid for the 2009-14 regulatory control period'. We are perplexed with this change particularly the AER has accepted that these costs can be passed through to customers and that the AER had accepted Endeavour Energy's application for the pass through of these costs[324]

As noted above, the AER has improperly ignored its prior determination or retrospectively changed the operation of certain aspects of its prior decision. For instance the decision to:

- retrospectively change the operation of the EBSS that applied to Ausgrid for the 2009-14 period.
- simply ignore the validity of its decision on the 2009-14 forecast opex.
- disregard the previous recognition of loss of synergy costs.

These instances undermined the validity of its decisions and the confidence in these decisions.

- We previously have expressed concerns with the narrow approach taken by the AER in relation to costs that it termed 'step change'. Such an approach simplistically ignore legitimate costs that reasonably reflects the opex criteria. The AER is required by the rules to assess forecast opex based on the requirements specified by the rules, i.e. the opex criteria and factors, and not by a simplistic and narrow approach, the validity of which by reference to the rules it has not demonstrated. We note that clause 6.12.2(4) of the rules requires the AER to state reasons for its by reference to the particular requirements of the rules relating to that decisions, in this case the opex criteria and opex factors.

Impact of complying with approved cost allocation method (CAM)

The AER rejected Ausgrid's costs that resulted from complying with the cost allocation method approved by the AER on 2 May 2014. The AER's reasons are similar to that it relied for rejection loss of synergy costs, that is, efficient base year costs provides sufficient funding for a prudent service provider to deliver standard control services.

In addition to the views expressed above about the AER's approach of 'assuming away' costs by relying on its 'benchmarked efficient base year' costs, we note that:

[324] AER decision on Endeavour Energy's retail project event pass through application – 23 December 2012 [CHECK]

- We were required by the rules to submit a new cost allocation method to the AER for approval. The AER and its consultant assessed our proposed CAM and found no significant issues with it; particularly in comparison with the allocation basis used by other DNSPs.
- We are required by the rules to apply the CAM to the 2014-19 period.
- We comply with this obligation of the rules. We recognise the impact of complying with this obligation on consumers and have sought to offset the majority of these costs.

Based on the approach the AER undertook in rejecting the cost impact of compliance with the approved CAM; we assume that the AER will apply this approach symmetrically in cases where compliance with the approved CAM will result in a reduction to forecast opex. That is, the AER will reject such reduction on the basis that such rejection would result in a 'base year costs' that would not be sufficient to deliver standard control services.

Broadbased demand management initiatives

The AER did not accept Ausgrid's proposal for an investment in broad based demand management to lower customer demand and defer capital expenditure in the long term interests of customers. The draft determination rejected the proposed program on the basis that the introduction of cost reflective pricing would deliver price signals enabling customer response sufficient to undermine the business case for broad based demand management.

Ausgrid agrees that the introduction of cost reflective pricing may result in reduced customer consumption and peak demand in future. However, we disagree with the conclusion reached in the draft decision that cost reflective pricing will have a material impact on the business case and that broad based demand management program is supplementary to cost reflective pricing.

Ausgrid re-assessed the business case for our targeted broad based DM program; including sensitivities for a range of impacts from future cost reflective pricing, and determined that there is only a modest impact on the cost effectiveness of the program. We estimate that the change would lead to only a modest delay in the project achieving a net positive NPV, still about 6.5 years. This is due to the likely limited take-up of any cost reflective tariffs in the near to mid- term and the poor effectiveness of broad market level tariffs in targeting local constraints. The program will deliver benefits for customers well in excess of costs, returning a positive net present value (NPV) early in the following regulatory period and a total NPV of $31 million by 2024.

Furthermore, the broad based demand management programs are complementary rather than supplementary with tariffs as they offer customers the necessary enabling technology necessary for a response to any future cost reflective tariffs. This has been recognised by the Productivity Commission[325] and quantified by Faruqui and Palmer[326]. In particular, Nicholas and Strengers, in their detailed Australian study on the flexibility of families' routines and their ability to respond to the energy market noted that:

> *without some form of enabling technology to aid families in responding to a price signal, the resultant demand response is likely to be limited constraining the ability of the tariff to effectively defer network capital investments.'*[327]

We consider the broad based demand management program reasonable reflects the expenditure criteria. On this basis, Ausgrid retains the proposal for a broad based DM program in the revised proposal, under the same terms as described in the initial proposal. The details of this proposal were contained in Attachment 6.12 '*Demand Management operating expenditure plan'* to our initial proposal.

Our response to the concerns expressed in the draft determination and further information on our demand management programs are attached to our revised proposal as Attachment 5.14.

Leaseback of head office building

We accept the AER's decision on the leaseback costs of headoffice building.

6.8 Revisions to our proposed opex

Based on our review of the AER's decision, we have not been persuaded of the need to change our forecast method or inputs in most aspects of our forecast opex.

We included in the initial proposal the efficient forecast opex for the 2014-19 period based on the latest information available at the time. Since the submission of the initial proposal, we have adopted a more aggressive and progressive target for improved labour productivity. This has resulted in an average improvement labour productivity of 6% p.a over the 2014-19 period.

In addition to this improved labour productivity, other management and reform initiatives have been more sucessful than initially expected. These additional savings have also been encomposed in our revised proposal. Specifically, the revised forecasted opex incorporates:

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[325] Productivity Commission, 2013, The costs and benefits of demand management for households

[326] Faruqui and Palmer, 2012, The Discovery of Price Responsiveness- A Survey of Experiments involving Dynamic Pricing of Electricity

[327] Nicholls and Strengers, 2014, Changing Demand: Flexibility Of Energy Practices In Households With Children

- Our acceptance of the AER's draft cost escalation. We note that the AER will update these at the time of the final determination. For this revised proposal, the AER's draft cost escalation resulted in a reduction of approximately $32 million ($2013/14) for the 2014-19 period.
- The latest information on our opex performance to date.
- Further improvements in forecasted labour productivity averaging 6% pa over the determination period with 2018/19 forecasted to have a cumulative productivity improvement of 26.6%. This is expected to result a reduction of approximately 1300 positions over the five year to 2019. This is in addition to the reduction made over the later years of the 2009-14 regulatory period.
- The impact of a revised capital program on our workforce and the consequential impact on forecast opex requirements.

Ausgrid's revised proposal for standard control services operating expenditure for the 2014-19 regulatory control period is 2,679.3 million ($2013/14) as shown in Table 35 below. This is a reduction of $163.5 million or 5.8% lower than the forecast opex submitted in the regulatory proposal. We have provided the revised opex model at Attachment 6.05.

Table 35 – Revised forecast operating expenditure over 2014-19 ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Forecast opex in initial proposal	565.1	566.2	574.2	568.9	568.4	**2,842.9**
Revised forecast opex to reflect performance to date and additional productivity	528.4	553.2	536.1	531.7	529.9	**2,679.3**
Reduction	**36.7**	**13.0**	**38.1**	**37.2**	**38.5**	**163.5**

Note: numbers may not add due to rounding.

Performance to date

In addition to a detailed consideration of the AER's draft decision on our proposed forecast opex, our revised proposal provides Ausgrid with an opportunity to incorporate the latest data and information upon which our forecast expenditure is based. Ausgrid's initial proposal forecast opex incorporated the savings expected from reform initiatives. Since this submission, Ausgrid's success to date in driving reform initiatives to deliver performance improvements has been better than expected.

We have therefore incorporated this better than expected performance in our revised forecast opex to ensure that these additional permanent savings are passed onto our customers. The improvement in the forecast opex requirements for the 2014-19 period, as compared to the forecast in the initial proposal, is approximately $163.5 million ($2103/14).[328]

Updated labour productivity improvement

In the sections above, we have outlined the reasons why we have not accepted the AER's draft decision on redundancy costs. We maintain the position of our initial proposal that the costs of exiting staff are legitimate business costs that any business would need to incur to ensure that the staffing level is appropriate for future needs and circumstances. Consequently, we have not revised our opex forecast to incorporate the AER's rejection of these legitimate costs. Rather, our revised forecasted opex reflects an updated rate of staff exits resulting from forecast improved labour productivity, that is higher than that initially forecasted and incorporated in the initial proposal. The higher rate of staff exits will result in an increase in staff exit costs, compared to our initial proposal, of approximately $115 million ($2013/14) for the 2014-19 period taking the total staff exit cost over the period to $186.6 million ($2013/14). Importantly, the ongoing benefit to our customers by 2018/19 is forecasted to be a reduction of approximately $176 million ($2013/14) per annum in total labour expenditure.

Table 36 shows the composition of Ausgrid's revised forecast opex.

[328] This includes the impact of updated cost escalation

Table 36 – Revised forecast opex requirements ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Maintenance	243.3	246.3	250.2	254.4	258.8	**1,253.0**
Operations & support	296.5	301.5	309.3	301.1	305.0	**1,513.4**
Other opex	4.2	8.6	7.2	8.2	8.9	**36.9**
Total business as usual opex	**544.0**	**556.3**	**566.7**	**563.7**	**572.6**	**2,803.3**
TSA loss of synergy costs[329]	5.3	14.4	14.5	14.6	14.8	**63.5**
Impact of transitioning to approved CAM[330]	3.9	4.0	4.2	4.2	4.3	**20.6**
Total costs without efficiency measures	**553.2**	**574.7**	**585.3**	**582.6**	**591.7**	**2,887.5**
Efficiency initiatives implementation costs	35.5	46.9	47.3	45.7	44.5	**220.0**
Efficiency / productivity savings[331]	-60.3	-68.4	-96.5	-96.6	-106.3	**-428.1**
TOTAL FORECAST OPEX	**528.4**	**553.2**	**536.1**	**531.7**	**529.9**	**2,679.3**

Note: numbers may not add due to rounding

Underlying opex

Table 37 shows the underlying opex net of the one-off redundancy cost. This revised underlying forecast opex reflects the additional savings that have been achieved to date or are forecast to be achieved over the 2014-19 period, the benefit of which will be passed onto customers. It also reflects a revised forecast productivity improvement that is higher than that forecasted in the initial proposals. It must be noted that the forecast opex in the initial proposal already incorporated significant savings expected from the reform process. The revised forecast opex builds on these savings to deliver an even better opex outcome for customers without compromising on safety and reliability. As noted above, K&L Gates report (Attachment 6.03) highlights that Ausgrid's redundancy conditions are not dissimilar to others in the industry.

Table 37 – Underlying forecast operating expenditure over 2014-19 ($ million, 2013/14)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Revised forecast opex	528.4	553.2	536.1	531.7	529.9	**2,679.3**
Redundancy costs	-28.9	-42.5	-39.9	-38.3	-36.9	**-186.6**
Underlying forecast opex	**499.5**	**510.7**	**496.2**	**493.5**	**493.0**	**2,492.8**

[329] These costs relate to fixed overheads that were previously absorbed by the Retail business.

[330] This CAM was submitted by Ausgrid to ensure that the CAM Ausgrid applies from 1 July 2014 is consistent with the AER's Cost Allocation Guideline. The previous CAM was prepared in accordance with IPART's guidelines as per transitional arrangement.

[331] These costs relate to 'one-off' redundancy costs and recurring outsourcing arrangement going forward with the benefits of these investments included in 'efficiency/productivity savings'.

7. Allowed rate of return

We have carefully reviewed the AER's draft determination on the allowed rate of return and the AER's reasons for it. However, we have not proposed any material change to the cost of capital in our revised proposal. Our revised proposal incorporates a rate of return on capital of 8.85 per cent. Our revised proposal supports the immediate adoption of a 10 year trailing average approach to calculate the return on debt that is consistent with the efficient debt management practice of Ausgrid and a return on equity that takes account of all relevant evidence.

In this chapter, we have set out our revised proposal on the allowed rate of return. In developing our revised proposal, we have fully considered both the AER's draft determination and its final rate of return guideline (guideline). We have also outlined areas of the AER's draft determination and guideline that we agree with and those that we do not agree with. Where we disagree with the AER's draft determination or its guideline, we have explained our reasons for this.

- We propose a rate of return of 8.85%, commensurate with the minimum efficient financing costs for a DNSP with a similar degree of risk as that which applies to Ausgrid over the 2014-19 period. The revised rate of return has been developed to promote long term stability both for customers and equity holders. This is well below the allowed rate of return for the 2009-14 regulatory period of 10.02% and reflects reductions in financing costs since the previous determination.
- Our proposed rate of return approach for setting both the allowed cost of debt and the allowed return on equity would provide return profiles commensurate with what is required to attract investment in long-lived electricity network assets.
- We propose an allowed return on debt of 7.98%, which has been calculated consistent with the 10 year trailing average approach set out in the AER's final rate of return guideline. This estimate is based on bond yield data for broad BBB[332] rated Australian corporate bonds on issue from 1 January 2004 to 31 December 2013. This is lower than the allowed return on debt of 8.82% set in the 2009-14 period and reflects the reduction in the benchmark efficient costs of debt under the staggered portfolio approach.
- In the draft decision, the AER considered that (subject to a lengthy debt transition) the allowed return on debt should be estimated using a 10 year trailing average approach that would be subject to annual updates throughout the regulatory control period. With the exception of the transitional arrangements and the choice of data service provider, this is consistent with Ausgrid's initial proposal. We agree with the trailing average approach for setting the allowed return on debt, but we do not agree with the AER's proposed debt transition, choice of data service provider and its assumed benchmark efficient credit rating.
- The application of the AER's proposed debt transition is inconsistent with a number of the revenue and pricing principles in section 7A of the NEL. In particular, the AER's proposed transition would not, over the 2014-19 period, provide us with a reasonable opportunity to recover at least the efficient costs of debt finance, nor give rise to prices that would allow for a return commensurate with the regulatory and commercial risks involved in providing direct control network services.
- The AER's proposed transition approach would not operate to minimise any difference between the allowed return on debt and the return on debt of a benchmark efficient entity with a similar degree of risk as that which applies to Ausgrid. It would also mean that the benchmark efficient approach for setting the allowed return of debt (the trailing average approach) would not be fully implemented for 10 years, i.e. not until the 2024-29 regulatory period. We consider that a debt transition that is not fully unwound until 1 July 2024 is not reasonable for firms that already issue debt on a staggered portfolio basis.
- Ausgrid has historically issued debt on a benchmark efficient staggered portfolio basis and the AER's proposed transition would significantly under-compensate Ausgrid based on current estimates of yields on 10 year BBB corporate bonds

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[332] We note that due to the limited number of long dated BBB rated bonds, the RBA and Bloomberg have typically relied on bonds rated in the broad BBB band, i.e. BBB-, BBB and BBB+

prevailing over the period February to June 2014. This includes because the AER's proposed transition applies not only to the risk-free rate component of the return on debt (which is relevant to the benchmark efficient entity hedging issue), but also to the debt risk premium component of the return on debt, which is irrelevant to the benchmark efficient entity hedging issue. In circumstances where an entity acting in accordance with the AER's benchmark efficient entity would be coming into the 2014-19 period with a cost of debt comprising a trailing average in respect of the debt risk premium component, the AER's transitional approach is unreasonable and illogical, even more so in respect of entities, such as Ausgrid who already implement a trailing average approach.

- We consider that the RBA is an independent and robust source of data for estimating yields on Australian corporate bonds and there is a clearly agreed approach between the AER and Ausgrid on how to adjust the RBA's estimate to an effective maturity of 10 years, where the effective maturity of the AER's broad BBB yield estimates are greater or less than 10 years. We also consider that the evidence presented in our initial proposal demonstrated that the benchmark efficient credit rating is currently BBB, not BBB+.
- We propose an allowed return on equity of 10.15%, which has been estimated using internally consistent estimates of parameters within the capital asset pricing model (CAPM). The cost of equity has been selected from a reasonable range that has regard to all relevant evidence including the CAPM (both the Sharpe-Lintner and Black versions), the dividend growth model (DGM), and the Fama-French 3 Factor Model (FFM) as required by 6.5.2(e)(1) of the NER. Our proposed return on equity also has regard to prevailing conditions as required by clauses 6.5.2(g) of the NER. Our proposed return on equity is significantly lower than allowed return on equity for the 2009-14 period of 11.82% and reflects lower required returns on equity currently than were required at the time of the previous determination.

Our revised rate of return has been developed to meet the requirements of the rules, to contribute to the achievement of the NEO as set out in section 7 of the NEL, and to be consistent with the revenue and pricing principles set out in section 7A of NEL. In particular, clause 6.5.2(b) of the rules provides that the allowed rate of return is to be determined such that it achieves the allowed rate of return objective, which is that:

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

As set out above, our proposed rate of return has been developed to be commensurate with the efficient financing costs of a benchmark entity with a similar degree of risk as that which applies to Ausgrid in providing standard control services.

In setting the allowed rate of return, clause 6.5.2(e) of the rules also require that the AER must have regard to:

> *(1) relevant estimation methods, financial models, market data and other evidence;*
>
> *(2) 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*
>
> *(3) any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.*

Consistent with the rule requirements, our proposed rate of return is commensurate with the minimum efficient financing costs for a DNSP with a similar degree of risk as that which applies to Ausgrid over the 2014-19 period.[333]

Our proposed rate of return has been informed by leading financial and economic experts and we have attached a number of expert reports and other evidence in support of our position, including reports from Competition Economics Group (CEG),[334] Frontier Economics,[335] SFG Consulting (SFG),[336] Professor Bruce Grundy,[337] NERA,[338] a letter from the Australian Office of Financial

[333] As required by clause 6.5.2(c) of the NER.

[334] Attachment 7.01 - CEG, Efficient debt financing costs, January 2015 and CEG, Estimating the cost of equity, January 2015.

[335] Attachment 7.02 - Frontier Economics, Cost of debt transition for NSW distribution networks, January 2015.

[336] Attachment 7.04 - SFG, The required return on equity: Initial review of the AER draft decisions, Note for ActewAGL, Ausgrid Essential Energy and Endeavour Energy, January 2015.

[337] Attachment 7.05 - Letter from Professor Bruce Grundy to Justin De Lorenzo - 9 January 2015.

[338] Attachmet 7.06 - NERA, Memo on Revised MRP estimates to 2013, 14 November 2014.

Management[339] and a Statement from the Group Chief Financial Officer Networks NSW regarding debt management practices including the specific circumstances of the NSW DNSPs (Ausgrid, Endeavour Energy and Essential Energy)[340]. The attached CEG reports reference an extensive number of relevant documents and expert reports, many of which were provided as attachments to our initial proposal submitted on 29 May 2014. Only new or updated expert reports are attached to this revised proposal.

We note, that additional detailed analysis is being completed that will elaborate on issues raised within SFG's attached report on the cost of equity for ActewAGL and the NSW DNSPs. SFG will also be preparing more detailed analysis on the value of imputation credits that we intend to provide to the AER as soon as possible. We have also requested Professor Bruce Grundy to provide updated analysis on the evidence of bias within the SL CAPM and a response to Associate Professor Handley's report on the cost of equity. We note that the substance of the analysis to be covered in these reports are raised in our revised proposal and supporting attachments. However, given the tight timeframe within which we are required to submit a revised proposal and the breadth of issues raised in the AER's draft decision, the analysis could not be completed in time to attach with our revised proposal. We will provide these reports to the AER as soon as possible, and at the very least before the closing date for submissions on the AER's draft decision for Ausgrid

The breakdown of our proposed rate of return is outlined in Table 38 below.

Table 38 – Initial and revised proposal rate of return (%)

Parameters	2009-14 Determination	Regulatory proposal	AER draft decision	Revised regulatory
Overall WACC	**10.02**	**8.83**	**7.15**	**8.85**
Return of equity	11.82	10.11	8.1	10.15
Return of debt	8.82	7.98	6.5	7.98
Gearing	60	60	60	60
Gamma	50	25	40	25

In this revised proposal we have responded to a number of the AER's constituent decisions on significant building block elements, in particular forecast operating expenditure and forecast capital expenditure. To the extent the AER, in its final decision, maintains that significant reductions to these forecast expenditure amounts is appropriate, the AER will need to consider the impact of these reductions on the appropriate rate of return allowance. In particular, such reductions are likely to significantly impact on credit ratings and parameters such as the equity beta. This includes also because any such final decision is likely to result in how stakeholders perceive the stability of the regulatory regime and the risks associated with it.

7.1 Return on debt

The AER's draft decision has agreed to the position put forward by Ausgrid in our initial proposal that the allowed return on debt should be estimated using a 10 year trailing average approach that will be annual updated throughout the regulatory period. However, the AER's draft decision proposes to transition Ausgrid to a trailing average return on debt allowance from an "on the day" estimate over 10 years.

We have serious concerns over the AER's proposed debt transition approach because it varies significantly from the cost of debt that would be incurred by a benchmark efficient entity facing similar risks as Ausgrid. The transition would, if implemented when rates remain at current levels, result in significant losses to Ausgrid relative to its efficient costs of debt finance over the period 2014-19. This is not consistent with the allowed rate of return objective, the revenue and pricing principles or the NEO, which require that a network service provider be provided with a reasonable opportunity to recover at least its efficient costs so as to promote the efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers of electricity.

[339] Attachment 7.08 - Letter from Michael Bath of the Australian Office of Financial Management to Steve Knight regarding domestic interest rate swaps, 5 January 2015.

[340] Attachment 7.09 - Statement from Group Chief Financial Officer, Networks NSW, January 2015.

The AER's draft decision did not accept our proposed approach to annually updating the cost of debt using data published by the Reserve Bank of Australia (RBA). The RBA is a highly reliable source for Australian financial market data and at present is the only provider that provides estimates with a target maturity of 10 years.

The AER's draft decision also assumed a benchmark efficient credit rating of BBB+. This is inconsistent with the market evidence presented in our initial proposal, which demonstrated that the benchmark credit rating for energy network firms is currently BBB and is expected to be BBB over the 2014-19 regulatory period.

The remainder of this section explains:

- The reasons why the staggered portfolio approach is the benchmark efficient practice for managing debt. The trailing average approach reflects the cost of debt raised on this basis and should be used to set the allowed return on debt for Ausgrid, without transition.
- A debt transition would only be appropriate where a DNSP is likely to incur costs to transition its debt management practices to the benchmark efficient staggered portfolio approach. This is not the case for Ausgrid.
- The AER's debt transition would not provide a return on debt that is commensurate with the efficient debt financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to Ausgrid based on the currently estimated cost of broad BBB rated debt. This result is contrary to the requirements of the NER and the Revenue and Pricing Principles contained in section 7A of the NEL.
- It would not have been possible, nor would it have been efficient for Ausgrid to undertake a swap based strategy at the time of the previous determination. According to both the Australian Office of Financial Management (AOFM) and analysis by UBS, liquidity for these instruments was at best 'thin' in the Australian market following the GFC.
- In addition to this, at the time of the previous determination, the final averaging period to be applied by the AER was actually in dispute. Further the averaging period for the next regulatory determination i.e. 2014-2019 was not known, so the effective termination date for any swaps entered into in 2009 was also unknown.
- Government ownership was not the reason that Ausgrid did not undertake the swap based strategy, Ausgrid's treasury managers were well aware of the potential of interest rate swaps and determined that the staggered portfolio approach was the efficient strategy for managing Ausgrid's debt portfolio, which is confirmed by the analysis from UBS, Frontier and CEG.
- Ausgrid considers that the RBA should be chosen as the data source for estimating the allowed return on debt and based on the data provided in our initial proposal a benchmark credit rating of BBB should be assumed.

The trailing average approach

The trailing average approach estimates the cost of debt issued on a benchmark efficient staggered portfolio basis. The AER's guideline correctly notes that in the presence of refinancing risks, the benchmark efficient entity would have managed a staggered debt portfolio. We agree with this position and say also that in the presence of interest rate risk, a benchmark efficient strategy would also be to manage a staggered debt portfolio. We note refinancing risks are relevant to consider when setting the allowed return on debt because they have material implications for the financial sustainability of Ausgrid in providing network services.

Refinancing risks are realised when a business requires new debt to replace maturing debt and there is:

- a lack of liquidity in debt markets to raise new debt to do so (i.e. no willing debt investors), and/or
- the cost of new debt is so high that the business will be unable to afford it.

Realising refinancing risks can lead to insolvency, which is what occurred for a number of businesses during the Global Financial Crisis (GFC) in 2008. Ausgrid's determination for the 2009-14 period was taking place in the midst of the GFC and significant refinancing risks existed at that time. Refinancing risks are still present today and large capital-intensive businesses are particularly prone to them. However, we agree with the AER that refinancing risks can be effectively managed by issuing a staggered debt portfolio.

Issuing debt with staggered maturities is also an effective way to manage interest rate risks because it diversifies a business' exposure to interest rates that prevail across time. When managing a large debt portfolio such as Ausgrid's, it is simply not feasible, or alternatively, economic, to use derivative instruments to lock-in the rate of interest on debt over a long term period for purposes such as budget certainty or matching interest costs with expected revenues and regulatory allowances.

The effectiveness of the staggered portfolio approach in reducing risks for Ausgrid is outlined in the attached statement from Justin De Lorenzo, Group CFO of Networks NSW, which operates across Ausgrid, Endeavour and Essential. In his statement, Mr De Lorenzo concludes that:

> *…it remains my firm belief that the most efficient debt management approach that reduces risks for the businesses remains the staggered portfolio average approach which is consistent with the trailing average approach applied by the NSW businesses.*[341]

These points are evidenced by the practice of unregulated infrastructure firms and most Australian corporates. As noted by UBS, the predominant debt management approach of non-regulated infrastructure firms such as ports, airports, roads and railways is to issue debt on a staggered portfolio/trailing average basis.[342]

For the reasons outlined above the benchmark efficient practice is to issue debt on a staggered debt portfolio basis. The AER agrees that this is what a benchmark efficient entity would do. The ability to recognise this benchmark efficient approach through a trailing average return on debt allowance has been made possible through the recent changes to the NER. The amendments, which provide for the return on debt being, or potentially being, different for different regulatory years in a regulatory period, allow a trailing average to be adopted to estimate the allowed return on debt, whereas in the past the rules required the return on debt to be estimated using one short-term observation period with no ability to update the return on debt component of the allowed rate of return during the regulatory control period.

Minimising any difference of the allowed return on debt to that of a benchmark efficient entity

Clause 6.5.2(k)(1) of the NER requires that in estimating the allowed return on debt, regard must be had to the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity. As outlined in our initial proposal, this revised proposal and the supporting attachments to these documents, the benchmark efficient return on debt for a business facing a similar nature and degree of risks as Ausgrid, is the cost of issuing debt on a fixed rate staggered portfolio basis. The cost of issuing debt on the benchmark efficient staggered portfolio basis can be estimated using the trailing average approach. We note that the ability of the trailing average approach to achieve the objective of clause 6.5.2(k)(1) was clearly highlighted in the explanatory statement to the AER's final rate of return guideline.[343] On this basis, we consider that applying the trailing average approach should be used to estimate the allowed return on debt for Ausgrid over the 2014-19 period.

Transition to the trailing average return on debt

Justification for a debt transition

The AER's draft determination proposes that a transition should be applied to move from the "on-the-day" approach to the trailing average approach for setting the allowed return on debt.

The application of any transition to Ausgrid involves a misapplication of the NER. By clause 6.5.2(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. The allowed rate of return objective is that the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider in respect of the provision of standard control services.

The AER has correctly recognised that the trailing average approach is the best measure of the efficient financing costs of a benchmark efficient entity. Ausgrid has already adopted an approach to financing its debt consistent with the trailing average approach: that is, a staggered fixed-rate debt portfolio, without conversion of the fixed-rate debt to floating rate debt. There is therefore no reason to apply a transition to Ausgrid in moving to the best measure. The imposition of a transition:

(a) delays the imposition of the best approach, and prolongs the use of an inferior approach;

(b) has been imposed on the basis of hypothetical issues said to arise in the case of a hypothetical entity in a very different position from Ausgrid, and which are therefore irrelevant to Ausgrid ; and

(c) would produce a result for Ausgrid that does not permit Ausgrid to recover its efficient cost of debt.

There are no relevant "impacts" on Ausgrid or on customers of Ausgrid that arise as a result of changing the methodology from the "on-the-day" approach to the trailing average approach. In fact, the only relevant "impacts" that arise for Ausgrid arise precisely because the AER proposes to apply the transitional arrangements to it - it is the application of these arrangements that will result in Ausgrid not being provided with a reasonable opportunity to recover its efficient debt financing costs over the period 2014-19.

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[341] Statement of Justin De Lorenzo, Group CFO, Networks NSW.

[342] Attachment 1.12 - UBS, *Response to the Networks NSW request for financeability analysis following the AER's draft decision of November 2014*, January 2015, p. 5.

[343] AER, Explanatory Statement, Final rate of return guideline, p. 109.

At a fundamental level, imposing a form of transition so as to avoid issues, which would arise by the immediate application of a preferred methodology could only ever be appropriate if those issues would in fact arise in relation to the entity in question. It is inappropriate to impose a transition to the best method – i.e. a delay, or partial delay, in the application of the best method – in respect of alleged issues that do not arise in the case of the entity in question. There is nothing in the rules that says that every entity has to have the same return on debt, or the same approach to the return on debt. Nor does clause 6.5.2(k)(4) require or permit the AER to have regard to impacts that are irrelevant to the service provider in question. Rather, on its proper construction, the reference to "impacts… on a benchmark efficient entity" in clause 6.5.2(k)(4) is a reference to impacts that are not idiosyncratic impacts on a particular service provider only, but are impacts that would also be incurred if the service provider was a benchmark efficient entity. It certainly does not refer to impacts that are irrelevant to the entity in question, which is how the AER appears to have interpreted the rule.

Further, the AER's approach of seeking to establish the characteristics of a single hypothetical efficient benchmark entity, and then analyzing issues that might arise for that hypothetical entity, is inconsistent with the rationale for the amendments to the relevant rules. In its 2012 rule determination, the AEMC emphasised that:[344]

(a) "efficient benchmark service providers may have different efficient debt management strategies";

(b) "debt management practices tend to differ according to the size of the business, the asset base of the business, and the ownership structure of the business";

(c) there was a problem with the "one-size-fits-all" approach under the existing rules, and that a one-size-fits-all approach should not be considered a default position; and

(d) "the regulator could adopt more than one approach to estimating the return on debt having regard to different risk characteristics of benchmark efficient service providers".

At the very least, the AEMC rule determination emphasizes that pursuant to amended clause 6.5.2, the AER may need to consider more than one type of benchmark efficient service provider. This is emphasized in the specification of the rate of return objective in clause 6.5.2(c), which states that the rate of return objective for a DNSP is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the DNSP. Likewise, clause 6.5.2(k)(4) refers to impacts on a benchmark efficient entity "referred to in the allowed rate of return objective" – that is, an entity with a similar degree of risk as that which applies to Ausgrid.

In the present case, it is clear that it was not rational, efficient, or economic for large service providers to enter into floating rate hedges or 5-year floating to fixed rate hedges, so as to match as best they can the regulatory return under the "on-the-day" approach. Rather, such entities would generally manage debt simply by means of staggered fixed-rate facilities, being an approach that would rationally be used by all entities under the trailing average return approach. Therefore, even if it was appropriate to posit "impacts" merely by reference to a hypothetical benchmark efficient entity (which is not the case), the AER has stipulated the wrong such entity in the case of Ausgrid. The relevant benchmark efficient entity in the case of Ausgrid is a large entity that relies upon staggered fixed-rate facilities to manage its debt and its debt risk profile.

The draft decision relies upon additional reasons for the imposition of a transition. The first of these relates to the debt risk premium component of the relevant debt. The draft decision correctly recognises that even in the case of the hypothetical entity posited by the AER (i.e. a smaller privately-owned entity that has floating rate debt, either directly or by the use of hedges, that will continue into the next regulatory period), the impact of the existing floating rate arrangements is only relevant to the risk-free rate portion of the debt, not the portion referable to the debt risk premium. In relation to the DRP component of the debt, the AER contends that benefits were obtained in the last period (due to a spike in the DRP) that need to be balanced out before the new methodology is applied, because otherwise the new methodology would perpetuate a gain. There are a number of considerable difficulties with this approach:

(a) It is not consistent with proper economic regulatory practice. Proper economic regulation of monopoly infrastructure employs a forward-looking approach to assess an appropriate amount of revenue based on the best available methodology. It is inconsistent with this approach to employ a methodology that does not properly assess the cost of debt, in the hope that the entity will obtain less than an appropriate return in order to balance up an alleged over-recovery in a previous period. Put another way, proper regulatory practice does not involve tallying up alleged over or under recovery and setting a rate of return, or any other building block, on the footing that it will balance out the ledger.

[344] AEMC, *Rule Determination*, 29 November 2012, at pp 84, 85, 86, 90

(b) It would not be consistent with the national electricity objective to select out an alleged case of over-recovery on one component in a single period without considering all other potential cases of over or under-recovery in that or any other period. This is simply impractical and inconsistent with proper regulatory practice. The alleged DRP "spike", if it led to "over-recovery" in the last regulatory period, necessarily caused under-recovery in the previous period as DRP was "spiking" but allowed DRP remained steady.

(c) As explained by Dr Hird in his report,[345] the calculations underpinning the allegation are incorrect and the alleged over-recovery is therefore factually incorrect. In fact, there was no over-recovery by reference to the AER's benchmark efficient strategy under the previous rules. Indeed, as explained by Dr Hird, looking over the 2009-14 period and taking into account Ausgrid's final averaging period, there would have been and under-recovery of costs.

(d) As a general rule, the AER's approach also requires a speculative assumption about the size of the DRP in the initial averaging period. That is unwarranted and liable to error.

Dr Hird also explains why the "NPV neutrality" reasoning advanced by the AER is incorrect. To have another roll of the dice of a method that locks in rates for 5 years on a single day does not promote NPV neutrality. A service provider may do better or worse than a "neutral" result. Further, to speak of adopting a previous methodology to promote NPV neutrality over the life of the asset makes no sense in circumstances where the RAB is constantly changing and being renewed.

These issues are dealt with in more detail in the following paragraphs.

Although not stated in the draft decision or the guideline, it appears that the AER relies on clause 6.5.2(k)(4) of the NER to impose a transition if it considers it appropriate to do so.[346] Clause 6.5.2(k(4) states that the AER must have regard to:

> *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.*

One matter should be immediately noted with respect to clause 6.5.2(k)(4). It is one of four matters to which the NER direct the AER to have regard in estimating the return on debt under clause 6.5.2(h). Another particularly relevant matter referred to in clause 6.5.2(k) to which the NER direct the AER to have regard in estimating the return on debt is the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity (clause 6.5.2(k)(1)). The other factors (the interrelationship between the return on equity and the return on debt, and the incentives that the return on debt may provide in relation to capital expenditure, particularly as to the timing of that expenditure) are also relevant. In estimating the return on debt it is unclear from the AER's draft decision how the AER has actively had regard to factors (1) to (3) in estimating the return on debt.

A transition may be necessary for businesses that do not currently manage their debt on a staggered portfolio basis. However, Ausgrid has consistently issued debt on a staggered portfolio basis and that is the current practice, as explained in the statement of Mr De Lorenzo. As outlined above, the AER has determined that this is consistent with what a benchmark efficient entity would do.

The AER's justification for the debt transition is based on advice from its consultant Associate Professor Lally. Lally's advice is that any network business that raised debt on a basis other than the 'on the day' approach, *may* have achieved a lower actual cost of debt than the allowed return on debt in their determination. Lally argues that any business that achieved a lower actual cost of debt (by any means including by using a staggered portfolio approach) was overcompensated in the past Ausgrid. Lally goes on to argue that Ausgrid should be under-compensated in the 2014-19 regulatory period to "average out" this perceived over-compensation and ensure no gain or less in net present value (NPV) terms (i.e.an NPV=0) outcome over the past two regulatory periods. The attached cost of debt reports prepared by Frontier Economics and CEG clearly demonstrate that this is the basis of the AER's transition approach as set out in the draft decision.[347] Therefore, rather than interpreting clause 6.5.2 (k) of the NER as requiring the AER to consider any additional costs/risks created by a change in the regulatory approach, the AER is interpreting this clause to support a transition that would result in windfall losses for Ausgrid, simply because it issued debt using a benchmark efficient, risk mitigating, staggered portfolio approach in the past.

We note that "averaging out" perceived over-compensation in a past regulatory period is not a justification under the NER, for applying a windfall loss to Ausgrid in the forthcoming period. Furthermore, the NPV=0 principle needs to be applied for future periods (and in *present* not *past* value terms) to provide the correct incentives for efficient investment in the electricity network. Applying the AER's debt transition would, if applied over the 2014-19 period, result in a net present value less than zero (i.e. NPV < 0) outcome by not allowing Ausgrid to recover at least its efficient costs of debt finance incurred for the provision of network services. This is inconsistent with the revenue and pricing principles in section 7A of the NEL.

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[345] Attachment 7.01 - CEG, Efficient debt financing costs, January 2015.

[346] AER, *Rate of Return Guideline: Explanatory Statement*, December 2013, p 120.

[347] Attachment 7.02 - Frontier Economics, *Cost of debt transition for the NSW DNSPs*, January 2015. CEG, Debt financing costs, January 2015.

The AER's proposal to apply the transitional arrangements to Ausgrid is not supported by the NER. The NER require a return on capital for each regulatory year of the 2014-19 period to be calculated by applying a rate of return for the relevant DNSP for that regulatory year that is determined in accordance with clause 6.5.2 to the value of the RAB. The allowed rate of return objective, by reference to which the return on debt is required to be estimated, is that the rate of return for a DNSP is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the DNSP. What is being determined pursuant to these provisions is a return on debt (and ultimately an allowed rate of return) that is commensurate with efficient financing costs in the relevant regulatory period. In this particular case, the efficient financing costs in the transitional regulatory control period (2014-15) and the efficient financing costs in the subsequent regulatory control period (2015-19).

To the extent the AER considers the "on-the-day" approach resulted in a cost of debt in the 2009-14 regulatory control period that was "too high" and resulted in "over-compensation", this is irrelevant to the efficient financing costs of a benchmark efficient entity in the 2014-19 period. To the extent there was any "over-compensation" in respect of the 2009-14 regulatory control period, that has no impact on the efficient financing costs of a benchmark efficient entity in the 2014-19 period. With respect to at least the debt risk premium component of return on debt, the efficient financing costs, by reference to the AER's benchmark efficient entity, are an average of the debt risk premiums that prevailed on average over the past ten years.

Windfall losses to Ausgrid just from maintaining its benchmark efficient approach

Ausgrid has consistently issued debt on a staggered portfolio basis and the AER has determined that this is consistent with what a benchmark efficient entity would do in the presence of refinancing risks. There are no relevant "impacts" on Ausgrid that arise as a result of changing the methodology from the "on-the-day" approach to the trailing average approach. In fact, the only relevant "impacts" that arise for Ausgrid arise precisely because the AER proposes to apply the transitional arrangements to it - it is the application of these arrangements that will result in Ausgrid not being provided with a reasonable opportunity to recover its efficient debt financing costs over the period 2014-19.

The degree of under-compensation is outlined in the tables below. In these circumstances Ausgrid can, and, consistently with the law and the rules, must be, immediately transitioned to the trailing average cost of debt approach.

Table 39 – Benchmark efficient return on debt v AER's transitional return on debt allowance (%)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Trailing average using an average of Bloomberg and RBA data	7.92	7.81	7.62	7.42	7.14	**7.58**
AER draft decision return on debt	6.51	6.36	6.19	6.03	5.90	**6.20**
Difference	-1.42	-1.45	-1.44	-1.39	-1.24	**-1.39**

Note: This assumes the AER's starting point for the debt transition would be rates prevailing from 28 February 2014 to 30 June 2014 as it has indicated to Networks NSW. We do not propose to use an average of the Bloomberg and RBA forecasts to estimate the allowed rate of return. However, we average the RBA and Bloomberg historical forecasts to isolate the impact of the debt transition in the table above.

Table 40 – Windfall loss on Ausgrid's notional debt portfolio due to AER debt transition ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Benchmark efficient debt portfolio	8,572	8,932	9,348	9,759	10,136	**n/a**
Under-compensation due to AER debt transition	121	130	135	137	127	**650**

Note: The notional debt portfolios are estimated as at the beginning of each financial year based on forecast capex and WACC within this revised regulatory proposal. We note that the impact of averaging the RBA and Bloomberg data sources is not covered in the above under-compensation. This under-compensation is based on the forecast rates outlined in the preceding table. We note that UBS has estimated a similar figure, but UBS uses the aggregate difference between our forecast return on debt and the AER's draft decision to calculate under-compensation on the combined starting RAB values for the NSW DNSPs.

The costs of unwinding debt to match arrangements implied by AER's transition approach

With regard to the need for transitional arrangements, the AEMC's consultant, SFG, outlined that, if there was a change in the approach to setting the allowed return on debt as a result of changes to the NER, some service providers may need to unwind existing financial arrangements. The AEMC's consultant stated that it was for this reason that the AEMC should consider transitional arrangements for the cost of debt.[348] Ausgrid would not need to unwind any existing financial arrangements to adapt to an allowed return on debt calculated using the trailing average approach.

However, to adjust its actual financing practices to match those implied by the AER's debt transition, Ausgrid would incur material costs to re-issue all of its existing debt over a short averaging period and then slowly refinance approximately 10% of its debt portfolio each year for the next 10 years. To unwind existing debt financing, Ausgrid would need to compensate its debt-holders for the difference between the committed interest costs on fixed rate debt and prevailing interest rates for 10 year debt. The estimated "mark-to-market" cost of refinancing Ausgrid's existing debt portfolio as estimated at November 2014, was approximately $1.02 billion. When this mark-to-market cost is combined with prevailing cost of debt for 10 year BBB debt, the total cost of matching Ausgrid's debt financing practices with those implied by the AER's debt transition would exceed even the windfall loss being faced by Ausgrid if it maintained its benchmark efficient debt strategy and the AER used the transition approach to setting Ausgrid's allowed return on debt for the 2014-19 period (as outlined above). These costs are neither efficient nor rational. However, without them, the "on-the-day" approach incorporated into the AER"s transition will not be an appropriate proxy for the return on debt for Ausgrid.

Efficient debt management under the previous framework

Under the previous rules, the AER set the cost of debt using one averaging period (at the time 10-40 business days). One incentive that was created by such an approach was for businesses to refinance all debt over the 10-40 day averaging period set by the AER because this would minimise the risk of incurring an actual cost of debt that was higher than that set by the regulator to the extent that they sought to manage their interest rate risk. However, issuing debt in this manner would have resulted in significant refinancing risks around the time of a regulatory determination. Importantly, the previous rules were written prior to the GFC, and as such were unlikely to have fully contemplated a benchmark efficient network service provider's exposure to refinancing risks. The previous rules, which provided for the return on debt to be estimated over one short time period and which did not provide for the return on debt to be able to be updated during a regulatory control period did not provide for a trailing average approach to be adopted.

The AER has devoted much effort to determining how it considers a "benchmark efficient entity" would have structured its debt portfolio under the previous "on-the day" regulatory approach. Even though the AER never defined the benchmark efficient strategy for issuing debt when implementing the previous rules, the AER has now determined that there is only one approach that a benchmark efficient entity could have adopted. The AER's draft decision concluded that the efficient debt management practice under the previous rules would have been to issue floating rate debt on a staggered basis, i.e. with maturities throughout the regulatory period and then use interest rate swaps to fix the base rate of interest to that prevailing over the averaging period applied by the AER for 5 years. This approach would have allowed a business to roughly match the base rate of interest to that applied by the AER.[349]

The AER's approach fails to:

(a) acknowledge that there may have been a number of different ways in which a prudent and efficient business could have sought to manage its debt costs under the on-the-day approach, including in light of the circumstances that prevail at the commencement of different regulatory periods; and

(b) have regard to the fundamental differences that exist between the various regulated entities and how these differences would impact on the approach taken to managing debt costs.

It is clear under the rules that there are differences between benchmark efficient entities. This is specifically recognised in the allowed rate of return objective, which refers to "a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider".

Moreover, and as noted above, the AER's proposed transition approach for setting the allowed return on debt would not even match the costs of transition for a business that followed its claimed benchmark efficient approach under the previous rules. The "on the day" approach for setting the allowed return on debt, from which the AER proposes to begin its transition, compensates businesses for the current cost of debt finance. However, the cost of debt incurred by a business that used the AER's claimed benchmark efficient approach would be a combination of the current base rate of interest (conventionally measured using the 10 year bank bill swap rate) and a trailing average DRP measured as the 10 year average DRP. This is a separate issue from whether hedging of the risk-free rate was undertaken.

Certain privately owned businesses did undertake the interest rate swap based approach referred to by the AER. However, as outlined in Frontier's report on the cost of debt transition, this was only in response to the regulatory approach to setting the allowed return on debt. The swap-based approach is not the observed practice of unregulated infrastructure firms. We note that it was actually possible for these businesses to hedge their base rate of interest over a 40-day averaging period using interest rate

[348] SFG, Rule change proposals relating to the debt component of the regulated rate of return, Report for the AEMC, 21 August 2012, pp. 52-58.

[349] This approach would not enable a perfect hedge of the base rate because interest rate swaps are set on the basis of the bank bill swap rate, which mostly (but not always) has traded at a slight premium to the risk free rate proxy used by the AER – 10 year Commonwealth Government Securities.

swaps because of the small aggregate size of their debt portfolios compared to larger businesses such as Ausgrid. These businesses' debt portfolios were, and still are, much smaller than Ausgrid's.

We note that for businesses that undertook the swap based strategy a debt transition based on the costs of transitioning from this approach to the trailing average approach may be appropriate. In contrast to the businesses that undertook the swap based strategy, all larger energy network firms issued debt using a fixed rate staggered portfolio approach under the previous rules.

Ausgrid's ability to engage in interest rate swap strategy and costs of doing so

Ausgrid, along with the other NSW DNSPs requested that UBS AG Australia (UBS) analyse the cost and ability of Ausgrid to issue debt using the swap based strategy, which the AER has referred to as the single efficient response to the previous approach for setting the allowed return on debt.

The UBS analysis demonstrates that the swap based approach was not available to the NSW DNSPs including Ausgrid at the time of the 2009-14 regulatory determination. Given the size of notional debt financing requirements across businesses that were facing regulatory determinations at the same time, it would have been impossible to hedge the required debt financing in the Australian market using interest rate swaps over the maximum 40 day period allowed by the AER under the previous rules (let alone the 15 business day averaging period actually applied by the AER) without causing market dislocation or exhausting available liquidity.

We also note that around the time of the AER's previous determination the AOFM was trading in swap markets at that time in order to unwind its $20.65 billion domestic interest rate swap portfolio. This is a similar magnitude of the same type of swap contracts (pay fixed receive floating) that the AER believes that Ausgrid and other NSW electricity businesses should have efficiently completed over 40 days. The AOFM managed to spread $15bn in swaps over more than six months from November 2008 to May 2009. Moreover, the AOFM transactions were spread over maturities of 0.18 to 8.25 years. The transactions that the AER believes that Ausgrid and other NSW electricity businesses should have completed within 40 days would all have been at the 5 year tenor – exacerbating the liquidity constraints faced by the AOFM. This is outlined in the attached letter from Mr. Michael Bath of the Australian Office of Financial Management (AOFM) to the CEO of TCorp.

The AOFM's letter summarises that:

1. Despite the wide spread of maturities, market liquidity could best be described as 'thin' during the onset and immediate aftermath of the financial crisis; and
2. Executing the swaps in a significantly shorter period would, in our view, have been problematic.

This evidence, illustrates that if Ausgrid had tried to undertake the swap based strategy it would have had to compete with the AOFM in an already thin trading environment for a specific maturity (i.e. 5 years to cover the regulatory period). This provides weight to the UBS analysis, which concluded that it would not have been possible for Ausgrid to undertake the swap based strategy over a 40 business day averaging period without causing market dislocation or exhausting available liquidity.

UBS analysis demonstrates that even if the NSW DNSP's were able to issue debt over an averaging period that was longer than the AER's maximum allowed averaging period of 40 business days (noting that the AER's allowed averaging period was actually only 15 days), it would be a significantly longer period than 40 days and would have provided a very poor hedge to base interest rates prevailing during the regulatory averaging period. Such an approach would also have exposed Ausgrid to much greater interest rate risks than issuing fixed rate debt on a staggered portfolio basis as Ausgrid did. The staggered portfolio approach enabled Ausgrid to achieve the following efficient outcomes over the 2009-14 period:

- Diversified interest rate exposure across time (i.e. hedged interest rate risks)
- Managed refinancing risks on Ausgrid's significant debt portfolio.

Final averaging period was unknown

In addition to the fundamental inefficiency of a swap based approach for Ausgrid at the time of the previous determination, there was significant uncertainty about the actual averaging period that would apply to Ausgrid in the final determination. Ausgrid was in dispute with the AER over the averaging period that should be applied in the determination right up to the AER's final decision. There were three potential averaging periods:

- 15 business days starting 2 June 2008. This was the period originally proposed by Ausgrid and rejected by the AER as being too removed from the start of the regulatory period;

- 15 business days starting 2 February 2009. This was the averaging period applied by the AER in its final decision – which was subsequently appealed by Ausgrid (EnergyAustralia at that time); and
- 15 business days, 18 August 2008 to 5 September 2008. This was the averaging period contained in the revised proposals of the NSW DNSPs and ultimately determined by the Australian Competition Tribunal as the period that should be used by the AER to set revenues.[350]

Any hedging that was actually carried out in or around the first two averaging periods would not have hedged Ausgrid's actual debt costs to the actual revenue allowance for the cost of debt, which was based on the third period. However, by the time the actual averaging period was known with certainty (i.e. after the appeal to the Australian Competition Tribunal was heard and decided in November 2009) it was in the past and impossible to go back in time and issue the relevant swaps. Moreover, this averaging period was first proposed by Ausgrid after the period had passed and was chosen as a form of compromise between its originally proposed averaging period and the AER's proposed averaging period. This topic is dealt with in more detail in the attached CEG report on the efficient cost of debt.[351]

Therefore, in the circumstances of Ausgrid where the AER refused to accept Ausgrid's averaging period – a position that was only overturned on appeal – it was simply impossible to enter into the swap strategy that the AER regards as "efficient" – at least not without taking on the risk that the period in which the swaps were issued would not end up being the period used to measure the 'on the day' cost of debt. In these circumstances, it is incorrect to assert that a swap strategy is one that would be employed by a benchmark efficient entity.

Government ownership and effect on Ausgrid's debt management approach

The AER's consultant Associate Professor Lally, has suggested that government owned businesses did not use interest rate swaps to try to match actual debt costs to those set by the AER because they:

> *are not subject to normal market signals and incentives, because they face low bankruptcy and refinancing risk, and possibly also because they borrow via another government entity (such as the QTC or the NSW Treasury Corp) and are thereby partially shielded from market signals.*[352]

This statement is incorrect. All of the NSW DNSPs (and indeed the Qld Distribution businesses) are subject to competitive neutrality regulations that ensure they face the same market signals and incentives as privately owned businesses on their cost of debt. As noted by the AEMC in its 2012 rule determination:

> *The difference between the State's borrowing costs and the costs faced by the state-owned service providers, commonly referred to as debt guarantee fees, represents consideration due to state taxpayers for accepting the business' credit risk…From the service providers' perspective, this mechanism ensures that they face borrowing costs that reflect the nature of their businesses, not the taxation powers of their government lenders.*[353]

The NSW DNSPs issue debt through the NSW Treasury Corporation (TCorp). However, all of the NSW DNSPs are required to pay a Government Guarantee Fee (GGF) in addition to the cost of debt incurred by TCorp, which issues debt on their behalf. This means that the total cost of debt incurred by the business is equal to that which would be faced by a stand-alone corporation without government support. An independent ratings agency such as Moody's or S&P provides a stand-alone credit profile for each NSW DNSP and the GGF is applied to ensure that each NSW DNSPs actual cost of debt is equivalent to the cost of debt for a privately owned firm with that stand alone credit rating. The GGF is in effect the debt risk premium the NSW DNSPs would incur if they raised debt in a global debt market in the way that private firms do.

The GGF scheme is designed in part to ensure that state owned corporations were operating at least as efficiently as privately owned businesses. The GGF also ensures that the NSW government and NSW citizens are not left uncompensated for the additional risk incurred by issuing debt on behalf of the NSW DNSPs. Indeed, the refinancing risks for the NSW DNSPs were real in the past and remain real at present. For the NSW government to intervene in the event of a default by Ausgrid would be an extraordinary event and could potentially affect the credit rating of the state government. For this reason, mis-managing its debt portfolio is not a trivial matter for Ausgrid. NSW DNSPs are strongly incentivised to produce equity returns above those implied by the regulator to their shareholders in the form of dividends and capital growth of the equity value of the firms. This is evidenced annually via

[350] See Application by EnergyAustralia and Others (No 2) [2009] ACompT 8, 69(k).

[351] Attachment 7.01 - CEG, Efficient Debt Financing Costs, January 2015.

[352] Lally, Transitional Arrangements for the Cost of Debt, November 2014, p. 28.

[353] AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012: Rule Determination*, 29 November 2012, p 87.

written commitments made by the board of the NSW DNSPs and the shareholders. The board and management are held to account to achieve the proposed returns. These returns are required net of the payment of the GGF. In this way the incentives experienced by NSW DNSPs is no different to those experienced by private firms.

In addition to facing a stand-alone cost of debt, each NSW DNSP is responsible for nominating the debt instruments and tenors that are issued to raise its required debt funding. This was the case in the past and continues to be the case presently. This demonstrates that the NSW DNSPs are very much exposed to "normal" market signals and would very much be exposed to the normal market signals outlined above.

Associate Professor Lally also suggested that the lack of hedging using swap transactions may have been because the NSW DNSP's were historically less aware of the full potential of swap markets. This statement is also untrue, which can be seen from the attached confidential statement from Justin De Lorenzo, Group CFO of Networks NSW. Ausgrid was well aware of the potential to engage is swap transactions, which would have allowed them to partially hedge their actual debt costs in the manner described by the AER. However, at the time the efficient debt management strategy chosen by Ausgrid was to diversify interest rate risks on its significant debt portfolio by issuing long-term debt on a staggered portfolio basis. The debt management policies past and present of Ausgrid, which have been provided to the AER following information requests, include a range of permitted instruments including interest rate swaps.

Transition will expose Ausgrid to greater risks compared to other businesses

The AER's debt transition may operate to protect certain businesses, but would, if implemented, be detrimental to others. For example, businesses that have large tranches of fixed rate debt maturing at the time of their next determination will be somewhat protected by the AER's transitional approach. For these businesses it would be impossible to immediately transition to a staggered portfolio of 10 year fixed rate debt with an equal spread of maturities due to existing financial instruments that will need to be unwound. These businesses are subject to significant interest rate risks (e.g. the potential for rates to increase rapidly and unexpectedly).

The AER's transition would set the allowed return on debt equal to the observed cost of debt around the time of its final determination for these businesses, with a lengthy transition to the trailing average. Therefore businesses that issued large tranches of debt maturing at the start of their next determination would be protected from changes in interest rates at the time of their final determinations.

Smaller businesses that followed the swap based strategy would have large volumes of swap contracts expiring at the time of their next determination leaving their base rate of interest floating at that time. These businesses would be able to convert their floating rate exposure into 10 different tranches of 1, 2, 3, to 10 year fixed swap rates so that they lock in the fixed swap rates that prevail in the AER's initial averaging period and have 10% of these expire each year. Base rates of interest could then be hedged at prevailing 10 year swap rates each year, thereby matching the AER's debt transition allowance, which adds a 10% weight to new cost of debt estimates each year.

We note that while these businesses would likely be more protected than the NSW businesses under the AER's debt transition, they would still face uncompensated costs. This is because they would only be able to issue swaps on the base rate of interest they face, the DRP component of their debt would still be a staggered portfolio/trailing average cost. In addition to this, they would incur hedging transactions costs for implementing a swap based strategy. In the past these costs would have been manageable given relatively small debt portfolios and greater swap market liquidity. However due to tighter capital market regulations implemented since the GFC and the European Sovereign Debt Crisis[354], entering into large volumes of swap transactions may be more difficult in future determinations.

Unlike other businesses, the NSW DNSPs including Ausgrid already issue debt efficiently on a staggered portfolio basis and will not have a base rate of interest that is floating at the time of the next regulatory period. In contrast to the businesses who have previously committed to a swap based strategy, the transition approach set out in the AER's draft determination exposes Ausgrid to interest rate mis-match risk and interest rate volatility. As outlined above, based on rates in February to June 2014, would result in Ausgrid incurring windfall losses for having undertaken the benchmark efficient staggered portfolio approach.

Cost of using interest rate swaps compared to the transitional return on debt

The draft decision states that the benchmark efficient practice under the previous rules would have been to issue a staggered debt portfolio of floating rate debt and then fix the base rate to the regulatory allowance. However, the AER's debt transition does not provide compensation for the costs of hedging in the manner that the AER assumes. The AER's debt transition provides

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[354] Attachment 1.12 - UBS, *Response to the Networks NSW request for financeability analysis following the AER's draft decision of November 2014*, January 2015, p. 13.

compensation based on the cost of issuing the majority of the business' debt portfolio at the prevailing 10 year rate for the total cost debt.

However, even if a firm used swaps in the way envisaged by the AER, it would still be paying a trailing average debt risk premium (incorporating higher DRP costs on debt issued in the past). More importantly, for larger businesses such as Ausgrid there are significant hedging transactions costs for entering into swap transactions across their entire debt portfolios. The AER's draft states that these costs are insignificant, but the attached analysis prepared by UBS demonstrates that these costs are actually quite significant.

UBS has estimated that due to the size of our debt portfolio Ausgrid, which would need to be re-issued at the same time as the debt portfolios of the other NSW DNSPs, we would need to issue debt offshore. UBS estimated that the costs of doing so, even for a firm with a credit rating of BBB+, would be in the order of $521 million across the NSW DNSPs (approx. $279 million for Ausgrid, $109 million for Endeavour and $133 million for Essential), even before costs of additional liquidity premium and currency related volatility.[355] UBS has indicated that the costs would be even greater at a sub-investment grade credit rating. However, the mark-to-market costs of unwinding existing debt would also need to be factored into these costs. The combined mark-to-market costs for the NSW DNSP's as estimated at November 2014 was approximately $1.92 billion (approx. $1.02 billion for Ausgrid, $349 million for Endeavour and $551 million for Essential). Therefore, even if an investment grade credit rating was assumed, the transition cost for the NSW DNSPs to move to the debt management strategy implied by the AER's proposed approach would be in excess of $2.4 billion (approx. $1.3 billion for Ausgrid, $458 million for Endeavour and $684 million for Essential) compared to no cost for an immediate transition to the trailing average approach.

Incentives for timing of efficient capital expenditure

Clause 6.5.2(k)(3) of the rules requires that in estimating the allowed return on debt, regard must be had to incentives that the return on debt may provide in relation to capital expenditure over the regulatory control period, including as to the timing of any capital expenditure. As outlined above, the allowed return on debt allowance under the debt transition approach would significantly undercompensate Ausgrid relative to its efficient costs of debt finance. This would also place significant pressure on Ausgrid's financial sustainability over the 2014-19 period both separately and in combination with reductions applied in the AER's draft determination to other components of the building blocks revenue allowance.

The under-compensation in relation to the allowed return on debt, provides incentives to defer capital expenditure in order to maintain financial sustainability and/or provide required returns to equity holders. Therefore, the AER's debt transition approach to setting the allowed return on debt provides incentives to defer prudent and efficient capital expenditure. By contrast, the trailing average approach would compensate Ausgrid for its efficient cost of debt.

Choice of data service provider

The AER's draft decision adopted an average of Bloomberg's Valuation (BVAL) curve and data on corporate bond yield from the Reserve Bank of Australia (RBA) to estimate the allowed return on debt. In this revised proposal, we maintain our initial position that where available the RBA data source should be used to estimate the trailing average cost of debt. As outlined in our initial proposal, we consider the RBA to be a highly reliable independent data service provider for estimates of yields on 10 year BBB rated Australian corporate bonds. Moreover, RBA data extends back to January 2005, which enables the use of a consistently calculated data series to estimate the trailing average cost of debt as far back as January 2005.

Benchmark efficient credit rating

In this revised proposal, we maintain our initial proposal that the benchmark efficient credit rating for energy network firms is BBB. As demonstrated in the market evidence presented in our initial proposal, the benchmark credit rating for energy network firms is currently BBB and is expected to be BBB over the 2014-19 regulatory period.

Debt raising costs

In this revised proposal we maintain our revised proposal on the required efficient costs of raising debt finance of 9.9bppa. This is based on the detailed analysis of debt raising costs that was completed by Incenta and attached with our initial proposal. We note that the AER has not considered the full range of efficient debt raising costs that are faced by the benchmark efficient entity. These include more than the transactions costs outlined by Incenta. They also include liquidity commitment fees and the costs of 3 months ahead financing. However, we have maintained a conservative approach to minimize the impacts of our costs on our customers and only incorporated a minimal 9.9bbpa figure for debt raising costs

[355] Attachment 1.12 - UBS, *Response to the Networks NSW request for financeability analysis following the AER's draft decision of November 2014*, January 2015, p. 12.

7.2 Return on equity

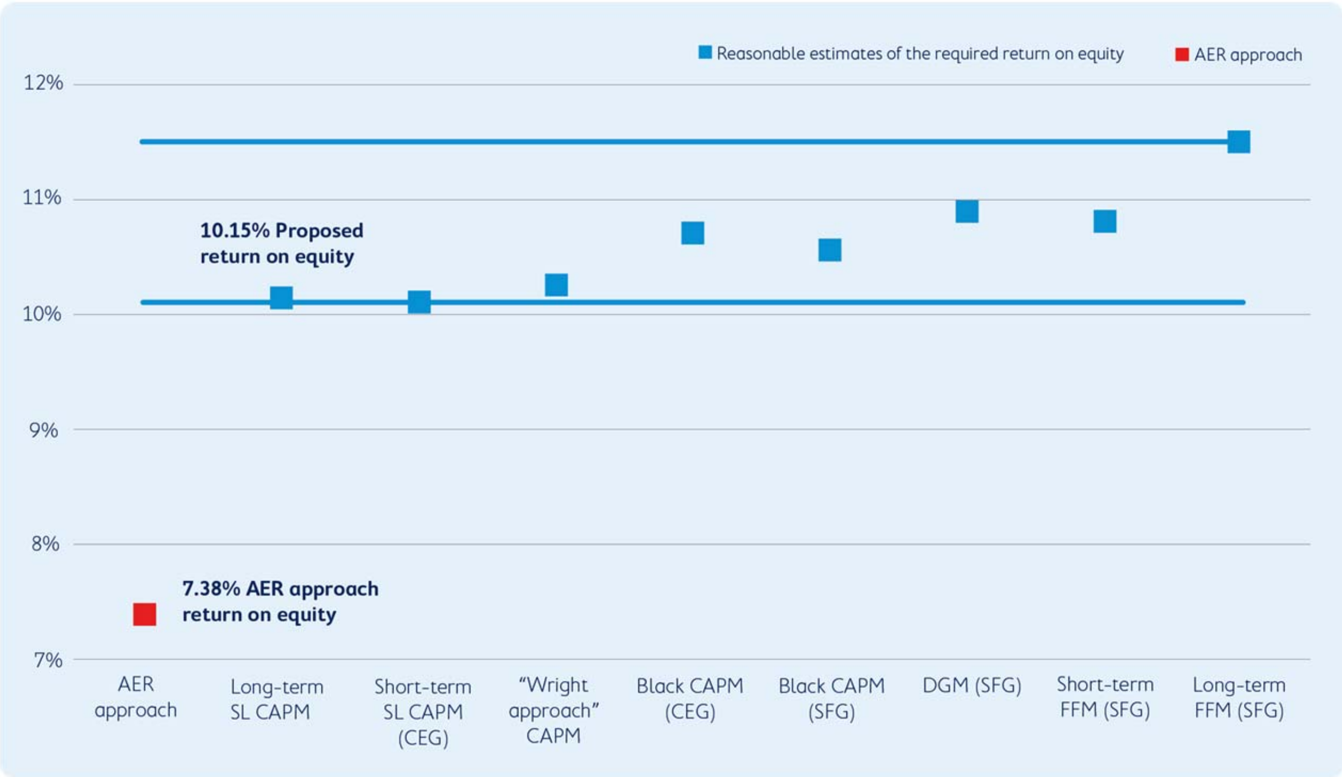
As required by clause 6.5.2(e)(1) of the NER, we have had regard to the range of relevant estimation methods, models, financial market data and other evidence to develop our proposed return on equity. Based on this analysis we determined a reasonable range for the benchmark efficient cost of equity for a benchmark efficient network business. We adopted a point within the reasonable range using the SL CAPM framework.

Our proposed point estimate for the return on equity is 10.15% and has been updated since our initial proposal to reflect the most recent estimates of the historical average MRP (6.56%) and the historical average real risk free rate combined with the latest forecast of inflation (4.77%). Our proposed estimate continues to uses internally consistent estimates of parameters within the capital asset pricing model (CAPM). We have reviewed the AER's draft decision and consider that an equity beta estimate of 0.82 remains reasonable when estimating the allowed return on equity using the SL CAPM.

We note that although we have used a point estimate using the SL CAPM as a base model, our estimate has been chosen having regard to the reasonable range for the benchmark efficient cost of equity. At the time of our initial proposal, this range was estimated to be 10.1 – 11.5%. Incorporating updated data, the reasonable range for the benchmark for the purposes of this revised proposal is estimated to remain 10.1% – 11.5%.

The top end of this range is based on the benchmark efficient cost of equity under long term average market conditions as estimated by SFG using the Fama French 3 Factor Model (FFM). The bottom end of the range is now based on CEG's estimate of the required return on equity using the SL CAPM populated with internally consistent estimates of the risk free rate and MRP over the period 28 February to 30 June 2014 and an equity beta of 0.82. Our proposed return on equity is at the lower end of the reasonable range that takes into account prevailing market conditions[356] and evidence from relevant financial models including the CAPM, the dividend growth model (DGM), and the Fama-French 3 Factor Model (FFM) as demonstrated in the graph below.[357]

Figure 37 – Reasonable range for the allowed return on equity (%)



In its draft decision, the AER reviewed much of the extensive information provided. However, the AER's draft decision did not have regard to all relevant evidence when estimating the benchmark efficient return on equity. In its final determination, we consider that the AER should have regard to the following evidence:

- Fama-French model based estimates of the cost of equity for the benchmark firm;

[356] As required by clause 6.5.2(g) of the NER.

[357] As required by clause 6.5.2(e)(1) of the NER.

- Empirical evidence of the low beta bias of the SL CAPM;
- Black CAPM based estimates of the cost of equity for the benchmark firm (using zero beta premium estimates from SFG); and
- DGM based estimates of the cost of equity for the benchmark firm

All of these sources of evidence contain relevant information as to what the true cost of equity for a benchmark efficient energy network firm is likely to be and therefore represents relevant information within the meaning of clause 6.5.2(e)(1) of the NER. In the following sections we set out our response to the AER's draft decision, including our updated estimate of the required return on equity estimated using the latest avail different relevant financial models.

Sharpe-Lintner CAPM

We have updated our estimates of the return on equity using the Sharpe-Lintner CAPM (SL CAPM). Using long-term data we estimate a required return on equity of 10.15%. This estimate is also consistent with prevailing estimates of the return on equity using short term data, which produces a required return on equity of:

- 10.1% using market data over the same averaging period as the AER proposed to use for its starting point estimate of the return on debt (i.e. 28 February to 30 June 2014).
- 9.8% using market data over the 20 business days to 19 December 2014.

As regards the relevant averaging periods for the various return on capital parameters, the AER's draft decision adopted an averaging period for the return on debt over the 2014-19 period of 28 February to 30 June 2014 for the first observation in their transitional return on debt allowance. As outlined above, we propose that the AER immediately applies a trailing average estimate of the return on debt (which implies a 10 year historic average estimate). However, at the start of 2014, the AER required Ausgrid to nominate averaging periods for each year within its debt transition approach that were fully prospective. Within these constraints Ausgrid nominated the longest possible period available to us at that time, which was the 28 February to 30 June 2014.

We do not consider that nominating an "averaging period" is required for the measurement of the risk free rate within the SL CAPM, this was a requirement of the previous rules. The current NER require the best estimate of the benchmark efficient cost of equity. As it is the position of Ausgrid that the point-estimate for the cost of equity is measured in an internally consistent manner that uses long term data (1883 - 2013) for the risk-free rate and the MRP, there is no need to specify a short-term averaging period to determine the point estimate for the cost of equity.

However, to the extent the AER maintains its position that it is necessary to specify a short-term averaging period for the measurement of the return on equity parameters (a position with which Ausgrid disagrees), Ausgrid submits that the period the AER should use is the period that has been agreed to measure the parameters for the return on debt for the 2014 year, being 28 February - 30 June 2014, and that this period be used to estimate the required return on the market as well as the risk-free rate. This period is prior to the commencement of the relevant investment period (being 2014-19) and, to the extent the AER's methodology for estimating the return on equity is to be adopted, would appear to be more appropriate than other alternatives. In particular, it is problematic to take an averaging period that significantly postdates the commencement of the investment period, as this will result in a figure which is demonstrably not the prevailing or appropriate figure for the 2014-2019 period.

In the sections below we discuss SL CAPM based estimates of the required return on equity.

Internal consistency of market risk premium and risk free rate estimates

Clause 6.5.2(e)(3) of the rules require that in determining the allowed rate of return, regard must be had to any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt. The AER's draft decision inconsistently applied parameters within the Sharpe-Lintner CAPM (SL CAPM).

As outlined in our initial proposal, the cost of equity is defined by the SL CAPM in the following way:

Cost of equity = Risk free rate + β (Expected return on the market – Risk free rate)

The AER's draft decision condenses the (Expected return on the market – Risk free rate) into the Market Risk Premium (MRP), which is often the practice. The AER's draft decision then places the most reliance on historical estimates of the MRP, but combines this with a short-term estimate of the risk free rate observed over a different period.

The historical studies relied on by the AER to estimate the MRP apply the following steps:

1. Estimate total yearly returns on Australian stocks (dividends plus capital gains). This is equivalent to estimating the return on the market.
2. Subtract the estimated yield on 10 year Commonwealth bonds for each year.
3. Average the estimates of this difference over historical time periods.

It is clear from steps 1-3 above that the historical studies of the MRP use historical risk free rate estimates. For internal consistency when applying the SL CAPM, the risk free rate used in the first part of the SL CAPM should be estimated on the same basis as the risk free rate used in estimating the historical MRP – as a historic average over the same time period.

In support of the AER's draft decision to apply inconsistent estimates of the risk free rate and the MRP, the AER's consultant Associate Professor Lally states that, unlike the risk free rate the MRP is unobservable. Lally, then concludes that if the long term average of excess returns is a good estimate of the MRP, then the AER's approach is justified.[358] We note that within the CAPM, it is actually the expected return on the market, which is unobservable and as a result the MRP is also unobservable. However, data on the risk free rate proxy (10 year Commonwealth Government Bonds) is much more readily available from published sources and can be applied consistently in the two parts of the SL CAPM equation where it appears. We note that the unobservable nature of the expected return on the market is not a justification for using inconsistent estimates of the risk free rate and the MRP.

Prevailing market conditions

The draft decision stated that our proposed 4.8% long-term estimate of the risk free rate of (1883-2011) was not reflective of prevailing conditions in the market for funds because the current 10 year risk free rate estimate is around 3%.[359] Clause 6.5.2 (g) the rules require an estimate of the benchmark efficient return on equity that has regard to prevailing market conditions, not simply a risk free rate that has regard to the prevailing conditions in the market for funds. In fact, the rules do not require an estimate of the risk free rate at all.

Parameters used within financial models to estimate cost of equity move over time, for example during financial crises it is likely that:

- The estimated risk free rate will become depressed below historic levels due to a "flight to safety" where funds are transferred away from risky investments into secure assets such as government bonds; and
- That the market risk premium will become elevated above historic levels.

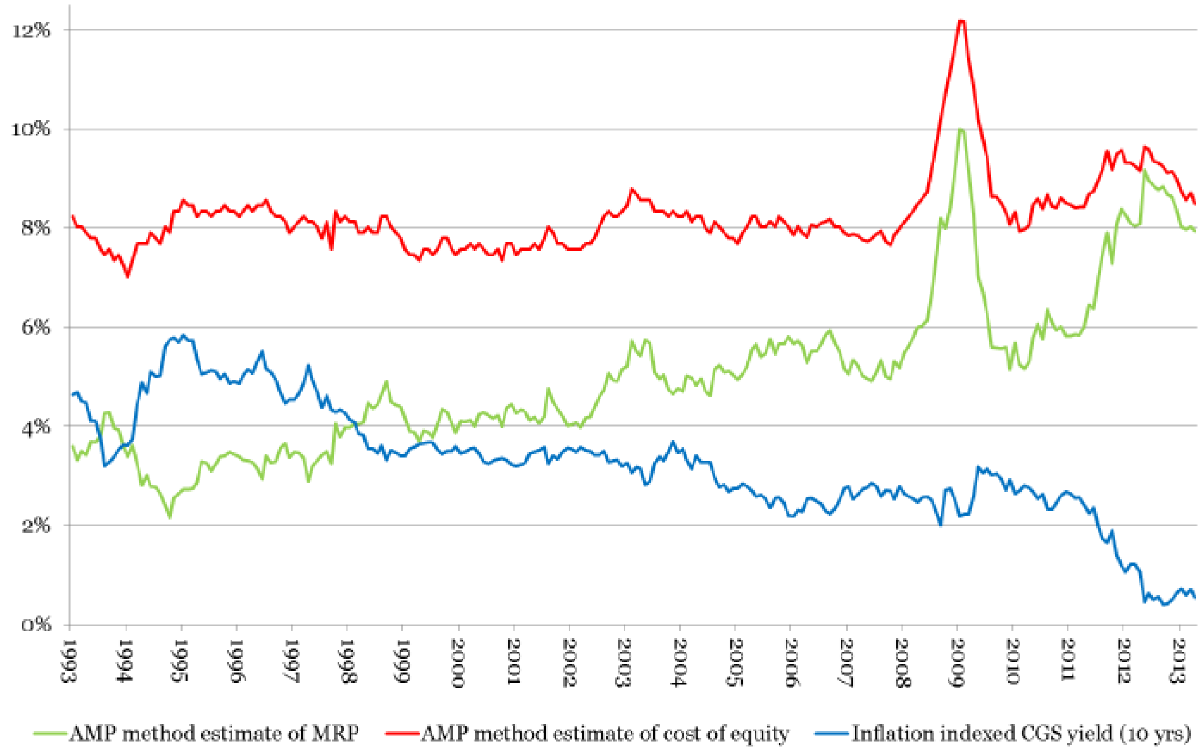
We do not submit that there is an exactly inverse relationship between the risk free rate and market risk premium parameters over time because the required return on equity may well change over time. However, if we only take the prevailing estimate for one parameter, then the resulting return on equity is unlikely to be commensurate with prevailing conditions in the market for funds. For example, if we only took the prevailing risk free rate and kept the long term MRP during a financial crisis, the return on equity would likely to be too low and if we only took the prevailing MRP during a financial crisis but a long term average for the risk free rate, the return on equity would be likely to be too high.

As demonstrated in the graph below, estimates of the risk free rate and the MRP vary over time. At times the two parameters move in opposite directions, resulting in a cost of equity for the market that moves over time but that moves less than either individual parameter and provides a more stable cost of equity estimate over time. The graph also illustrates that the cost of equity may actually move in a different direction to the risk free rate or the market risk premium at any point in time. This demonstrates the importance of estimating inter-related parameters, such as the risk free rate and the MRP, consistently. Doing so is required to ensure that the estimated overall return on equity is reflective of prevailing market conditions.

[358] Lally, Review of the AER's methodology for the risk free rate and MRP, March 2013, pp. 26-27.

[359] AER, Draft Decision, November 2013, Attachment 3, p. 78

Figure 38 – Movements in the real risk free rate, market risk premium and the real cost of equity over time



Source: CEG, WACC estimates, A report for NSW DNSPs, May 2014, p.60, as updated by CEG.

We recognise that the AER has raised concerns about whether our proposed return on equity is commensurate with the prevailing conditions in the market for funds. To address this concern we have undertaken additional analysis in this revised proposal.

First, we have updated the historical estimates of the risk free rate and the MRP to incorporate the most recent available data. The internally consistent long term estimates are:

- Risk free rate estimate of 4.77% (1883-2013)
- Expected return on the market of 11.33% (1883-2013)
- MRP estimate of 6.56% (1883-2013)

Combined with an equity beta of 0.82 this provides an estimated cost of equity of 10.15%.

Second, we have updated our estimate of the cost of equity using internally consistent short-term estimates of the risk free rate and the market risk premium. The internally consistent short-term estimates are:

- Risk free rate estimate of 3.94% (using rates observed over the AER's initial debt averaging period, 28 February to 30 June 2014)
- MRP estimate of 7.48% (using rates observed over the AER's initial debt averaging period, 28 February to 30 June 2014)

Combined with an equity beta of 0.82 this provides an estimated cost of equity of 10.1%.

Third, we have estimated the cost of equity for the benchmark firm using prevailing parameter estimates within the DGM, FFM and Black CAPM frameworks. All of these estimates indicate that our proposed estimate of 10.15% is at the lower end of plausible estimates within the reasonable range for the allowed return on equity. Estimates of the required return on equity using these models are discussed further below.

Volatility in the estimated cost of equity

The AER's draft decision states that a short-term averaging period provides a reasonable estimate of the prevailing risk free rate without exposing service providers to unnecessary volatility.[360] We disagree with this statement. As demonstrated below, the estimated risk free rate varies significantly even using a 20 day averaging period. Clearly, using a short term risk free rate and combining this with an MRP estimate based primarily on historical averages produces highly variable results over even a short period of time.

Figure 39 – AER's approach to cost of equity vs long term approach (%)

Source: Ausgrid and NERA analysis.

The estimated risk free rate is at historic lows and combining this estimate with a long term MRP exposes Ausgrid to unnecessary volatility and unreasonably low compensation compared with our proposed approach. For example, the AER's draft decision estimated the allowed return on equity to be 8.10% and in just two months from October to December 2014 the return on equity estimated using the AER's approach dropped to 7.63%. This is because the 10 year government bond rate dropped from 3.55% to 3.08% (using the 20 business days to 19 December 2014) and under the AER's approach there is no recognition that the underlying expected return on the market portfolio is unlikely to have changed so significantly. We note that 10 year CGS yields have recently fallen even further, and using a 20 business day averaging period to 14 January 2015, the estimated risk free rate drops to 2.83% and the cost of equity to 7.38%.

By comparison, the return on equity using internally consistent estimates of the risk free rate and the MRP in the SL CAPM provided a return on equity of 9.8% using the 20 business days to 19 December 2014, which only differs marginally compared to the CEG's estimated return on equity of 10.0% using internally consistent short-term estimates of the risk free rate and the MRP from May 2014.

The lower variance in CEG's estimates of the cost of equity using short-term rates illustrates again that at any point in time, the estimated risk free rate may have fallen but investors required return for investing in equities may not have. Indeed it is very likely that during times of financial market uncertainty, rational investors would shift funds into secure assets such as 10 year Commonwealth government bonds. At the same time, the expected/required return on equities would likely increase to compensate investors for higher perceived risks in the market. CEG makes similar observations.[361]

[360] AER, Draft Decision, November 2013, Attachment 3, p. 77

[361] Attachment 7.03 - CEG, Estimating the cost of equity, equity beta and MRP, January 2015, - see especially Section 4 and Appendix A.

In contrast to the AER's internally inconsistent approach, our proposed approach has not produced materially different estimates of the required return on equity since our initial proposal. Our initial proposal incorporated an allowed return on equity of 10.11% and our revised proposal incorporates an allowed return on equity 10.15%. This is largely due to our approach of applying internally consistent estimates of parameters as required by the NER, but is also underscored by our approach to consider evidence from all relevant financial models as required by the NER, rather than isolating consideration to one single model.

Wright approach to implementing the CAPM

The AER has characterised the "Wright" model as a separate specification of the SL CAPM. We note that the Wright approach is not a separate specification of the SL CAPM. The Wright approach is an estimation approach for populating the SL CAPM. The approach advocated by Professor Wright is to estimate the expected real return on the market as the historic realised, real return on the market portfolio. We apply expected inflation of 2.5% to this figure to estimate an expected nominal return on the market portfolio, which is one parameter required within the SL CAPM framework. We note that using a long term average of expected/required returns on equity is particularly reasonable when considering investment in long-term infrastructure assets. This approach provides an estimated cost of equity for regulated network firms of 10.25% during the AER's proposed averaging period for the initial return on debt observation.

Ausgrid notes that the Economic Regulation Authority (ERA) of Western Australia has recently applied an approach consistent with that suggested by Professor Wright to estimate the required return on equity for rail infrastructure businesses.[362]

Equity beta – empirical estimates

The AER's approach for estimating the cost of equity uses an estimate of the SL CAPM equity beta that relies principally on the AER's prior expectations and equity beta estimates for Australian firms with regulated energy network assets. In our initial proposals and supporting reports we outlined that Australian estimates of equity beta rely on a small sample of listed energy network firms (currently only 4 listed firms remain in the AER's equity beta sample). This small sample size affects both the stability and reliability of the Australian equity beta estimates.

The AER's draft decision dismissed our concerns about the reliability of Australian equity beta estimates given the small sample size, stating that equity beta estimates from its consultant Olan Henry produce consistent results of 0.4 - 0.7 over time.[363] We do not consider that the Australian estimates of equity beta are stable or by themselves statistically reliable over time for the reasons outlined in our initial proposal and supporting attachments.

In addition to this, we note that CEG have conducted further analysis on equity beta estimates for Australian firms. CEG's analysis illustrates that Australian equity beta estimates for non-resources and non-financial firms over the AER's estimation period have been significantly depressed by the impacts of the recent mining boom and the GFC. These major stock market events aren't expected to prevail over the 2014-19 regulatory period so it is questionable whether equity beta estimates materially affected by these events should be used to estimate the allowed return on equity over 2014-19. CEG's detailed findings are outlined in the cost of equity report from CEG, attached with this revised proposal.

CEG recommends that based on this new evidence we should reconsider the weight applied to Australian equity beta estimates relative to more statistically reliable evidence using US data over the 2002-2012 estimation period. Applying equal weighting to US and Australian equity beta estimates results in an overall equity beta estimate of 0.85. However we have taken a conservative approach and maintained our initial estimate of equity beta, 0.82, when estimating the benchmark efficient return on equity using the SL CAPM framework.

Equity beta – international evidence

Our initial proposal submitted that weight should be placed on the relatively robust empirical estimates of equity beta for US energy network firms. However, the AER's draft decision placed no substantive weight on estimates of equity beta from US firms or other foreign comparators. We note that this is inconsistent with the practice of most regulators in Australia and overseas, the vast majority of which use foreign comparators when estimating the appropriate value for equity beta. The practice of other Australian and overseas regulators in relation to beta is outlined in CEG's report on the cost of equity, attached with this revised proposal.

In foreign jurisdictions that used the CAPM and subsequently derived a beta estimate from a sample of comparators, CEG found that the regulators almost always included foreign firms in their sample. The remaining regulators that did not obtain their own sample of comparators were nevertheless influenced by the equity betas of foreign firms, either by referring to reports from their consultants that were based on data including foreign firms, or by referring to the equity beta decisions of other regulators.

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[362] ERA, Review of the method for estimating the Weighted Average Cost of Capital for the Regulated Railway Networks – Revised Draft Decision, 28 November 2014.

[363] AER, Ausgrid draft decision, Attachment 3, pp. 258-260.

The AER's draft decision stated that the pattern of international results for equity beta are not consistent over time, but that they provide limited support for an equity beta estimate at the top of its empirically estimated range for Australian equity betas of 0.4 – 0.7. We do not consider that this gives reasonable weight to evidence on equity beta from foreign comparators, particularly the relatively statistically robust estimates of equity beta from the US data included in our initial proposal. The evidence from US comparators presented in Ausgrid's initial proposal should be used to determine the range for equity beta due to the small sample size for Australian equity betas.

We also note that the AER's draft decision listed a range for international equity beta estimates of 0.45 to 1.14. However, the low end of this range is based on raw equity beta estimates. The range for these estimates once they are appropriately re-levered to a benchmark gearing assumption of 60% consistent with the AER's approach is actually 0.65 to 1.14.[364] Furthermore, as demonstrated by CEG, the 0.65 estimate relies on 1 year of data from 2 UK firms estimated by FTI consulting, which FTI recommended that OFGEM should not into account as it may reflect unusual market conditions. FTI recommended that OFGEM maintain its equity beta range of 0.9-0.95.

Excluding the FTI results for the 2 UK firms (that were ultimately not relied on by OFGEM) provides an estimated range for equity beta from the international evidence of 0.75 (based on a Brattle Group sample of 7 European firms) to 1.01 (based on a Brattle Group estimate for US firms) using average beta estimates, re-levered to the AER's benchmark gearing assumption of 60%. All of this suggests a beta estimate well above the AER's 0.4-0.7 range even before considering what impact the extensive evidence on low beta bias within the SL CAPM framework should have on the final cost of equity estimated using this model.

Low beta bias in the CAPM

There is well established finance literature demonstrating that the SL CAPM under estimates the cost of equity for stocks with a regression based equity beta estimate of less than 1. The academic literature was reviewed in a 2011 report by Professor Bruce Grundy, which concluded that the SL CAPM should be rejected as the true underlying model for explaining returns on equity. The reasons for this include:

- The empirical regularity that regression based estimates of the SL CAPM equity beta underestimate the measured returns on equity for stocks with a regression based beta estimate of less than 1.
- The required return on a zero beta portfolio is likely higher than the observed risk free rate.

As we noted in our initial proposal, the FFM and Black CAPM attempt to correct for the low beta bias identified by the significant body of empirical research. The following sections outline the estimates from these models and how and why the AER should have regard to the evidence from these models.

Black CAPM estimates

The Black CAPM has both empirical and theoretical support within the academic literature. The AER only has regard to the "theoretical implications" of the Black CAPM. However, the empirical evidence is equally if not more relevant in the context of setting the allowed return on equity. The empirical evidence enables the AER to actually estimate the cost of equity using the Black CAPM and address the low beta bias present when estimating the cost of equity using the SL CAPM framework. This provides an allowed return on equity that is commensurate with the efficient financing costs of benchmark efficient equity with a similar degree of risk as that which applies to Ausgrid as required by clauses 6.5.2(b),(c) and (f) of the NER.

The AER's consultants McKenzie and Partington claim that the problem of estimating the benchmark cost of equity within the Black CAPM framework is estimating the return on the zero beta portfolio, which can be very sensitive to the choices made in its estimation. However, even if correct, the sensitivity of zero beta premium estimates to choices made during the estimation procedure should not preclude the AER or others from attempting to estimate the zero beta premium. We note that both CEG and SFG independently attempted to estimate the zero beta in reports attached to Ausgrid's initial proposal. The results produced at that time were fairly consistent. CEG has updated its estimate of the zero beta premium and estimates a required return on equity for the benchmark firm using the Black CAPM that remains consistent with both the earlier estimates and SFG's updated estimate of the cost of equity using the Black CAPM.

McKenzie and Partington's conclusion in their report for the AER is that they would not recommend using the Black CAPM alone to estimate the required return on equity, due to difficulties present when estimating the zero beta premium. However, McKenzie and Partington also state that in principle the Black CAPM might be used for estimating the benchmark efficient return on equity in combination with other models proposed by NSPs.[365] We agree with this principle and it is what we have applied in this revised

[364] We note that re-geared estimates were not possible to derive for estimates used by the Alberta Utilities Commission.

[365] McKenzie and Partington, October 2014, p. 25.

proposal. Given the broadly consistent, independently derived estimates of the zero beta premium from CEG and SFG, we have included estimates for the benchmark efficient cost of equity using the Black CAPM framework in determining our reasonable range for the required return on equity for the benchmark efficient firm.

CEG's updated cost of equity estimates using the Black CAPM are:

- 10.5% using an averaging period for the expected return on the market and MRP of the 20 business days to 19 December 2014.
- 10.7% using an averaging period for the expected return on the market and the MRP consistent with the AER's cost of debt averaging period for Ausgrid of 28 February to 30 June 2014.

SFG's updated cost of equity estimate using the Black CAPM is:

- 10.5% using an averaging period consistent with the AER's cost of debt averaging period for Ausgrid of 28 February to 30 June 2014.

Fama-French model

The AER's draft decision disregards evidence on the benchmark efficient cost of equity from the Fama-French 3 factor Model (FFM). We consider that the FFM is a relevant model that should be had regard to when estimating the required return on equity, consistent with clause 6.5.2(e)(1) of the NER.

The AER's reasons for disregarding evidence from the Fama-French model as articulated in its draft decision were that:

- the FFM does not appear sufficiently robust and is sensitive to different estimation periods and methodologies;
- It is not clear that the model is estimating ex-ante priced risk factors;
- the FFM suffers a lack of theoretical foundation; and
- the FFM is relatively complex to implement.

The SFG report on the cost of equity and the expert opinions of Professor Bruce Grundy, both attached to this revised proposal indicate that these issues with the FFM are either not true or are overstated by the AER. Indeed many of the AER's criticisms apply to its foundation model the SL CAPM as well as most financial models used for estimating the required return on equity.

The AER states that the FFM does not appear sufficiently robust. However, we note that there is a significant body of academic research, including at least 20 years of empirical evidence that the FFM performs better than the SL CAPM at predicting stock returns.[366] Further, as noted in our initial proposal, the contribution of the Fama-French Model to improving predictability of stock returns has been recognized by the Nobel Prize Committee in its reasons for awarding the Nobel Prize for Economics to Eugene Fama. These factors indicate the FFM is indeed a sufficiently robust model for estimating the required return on equity that the AER should have regard to, consistent with clause 6.5.2(e)(1) of the rules.

With regard to sensitivity to different estimation periods, we note that this is equally true for the SL CAPM. As demonstrated in CEG's attached report on the cost of equity, estimates of the SL CAPM equity beta are highly variable over time. In addition to this, as demonstrated above, the AER's estimates of the risk free rate parameter in particular is highly variable over time. This does not prevent the AER from considering the SL CAPM a relevant model to have regard to when setting the allowed return on equity.

The AER's draft decision notes that the FFM is sensitive to estimation methodologies. Again, this is also true for the SL CAPM. As demonstrated by the AER's own analysis in its draft decision, estimates of the MRP parameter that it uses to populate the SL CAPM vary significantly depending on whether a DGM or historical excess return approach is used. This is also true for the equity beta parameter, for which many different estimation methods are available including various regression techniques and the relative risk based approach using DGM estimates of equity returns for energy network firms relative to the market portfolio of stocks.

The AER's draft decision also states that the FFM is not clearly estimating ex-ante priced risk factors and lacks theoretical foundation. In response to this we note the significant body of research showing that the FFM perform well in predicting future stock returns (in fact it performs better than the SL CAPM). This strongly suggests that the FFM framework captures information that is in fact priced into the cost of equity. Professor Bruce Grundy provided the following advice on these points:

[366] Attachment 7.05 - Letter from Professor Bruce Grundy to Justin De Lorenzo, 9 January 2015, p. 2.

it is correct that the Fama French factor models are empirical models in the sense that they seek to describe empirical regularities in the finance data. However, empirical models are at the heart of all science. Newton's theory of universal gravitation was an empirical model designed to fit the empirical observation. Newton discovered within the empirical data, a factor that explained (at least based on the data available to him) the observed strength of gravitational forces. The only theoretical foundation for Newton's theory was that it explained the empirical evidence. There was no theoretical foundation beyond that. Claiming that an empirically derived model should not be relied on because it lacks "theoretical foundations" implies that there is some form of 'truth' which is known and cannot be falsified by empirical observation. In this context it would appear that the AER regards the Sharpe Lintner CAPM model as the relevant source of 'truth'. I do not regard such a position as consistent with the scientific method.[367]

Professor Grundy also outlines that multi-factor models such as the FFM do have a strong theoretical basis. He notes that financial theorists view the empirically derived factors in the FFM as proxies for changes in investment opportunities.[368] The AER's consultants McKenzie and Partington also demonstrate that multi-factor models such as the FFM have a strong theoretical basis in the Arbitrage Pricing Theory, which they attribute to Ross (1976).

Arbitrage Pricing Theory predicts that the return on equity is linearly related to a number of factors. Consistent with Arbitrage Pricing Theory, the FFM assumes that there are factors common to specific stock portfolios that affect stock returns, in addition to the expected returns on the market portfolio. McKenzie and Partington note that the SL CAPM is also consistent with Arbitrage Pricing Theory if it is assumed that the market portfolio is the only common factor affecting stock returns. We note that in contrast to the SL CAPM, the FFM adopts the more realistic assumption that there are additional common risk factors that are being priced by investors.

Finally, the AER's draft decision states that the FFM is relatively complex to implement. However, as noted by SFG in its report on the cost of equity, the FFM model can be implemented using the same approaches used by the AER to estimate parameters within the SL CAPM. Within the FFM:

- The risk free rate can be estimated by reference to 10 year CGS yields;
- the market risk, size and value premiums can all be estimated by reference to historical averages; and
- the betas for the market, size and value premiums can all be estimated by regressions of comparator stocks to returns on the SMB and HML portfolios.[369]

Therefore, the AER cannot disregard the FFM on the basis that it is sensitive to estimation periods and estimation methods used because the SL CAPM faces these very same problems and is not disregarded by the AER. The AER cannot disregard the FFM on the because of a lack of theoretical foundation, because as outlined by Professor Grundy there is a strong theoretical basis for the FFM. In addition, it would not be consistent with the scientific method to simply ignore empirical evidence indicating the FFM does in fact capture ex-ante priced risk factors. Finally, the AER cannot disregard the FFM on the basis that it is relatively complex to implement. The FFM can in fact be implemented using the same estimation procedures applied by the AER to estimate parameters within the SL CAPM.

For the reasons set out above, and consistent with clause 6.5.2(e)(1) of the NER we submit that the AER should have regard to estimates of the required return on equity produced by the FFM. SFG have provided the following updated estimate of the benchmark efficient cost of equity using the FFM:

- 10.8 % using an averaging period for the risk free rate of 28 February to 30 June 2014.

The AER's consultants, McKenzie and Partington state that it is "unclear" whether the FFM, either alone, or in combination with other asset pricing models, would be expected to result in a materially better allowed return on equity estimate. However, their view is that the use of the FFM, alone, would not result in a better estimate of the return on equity. McKenzie and Partington also assert that the FFM's weaknesses are becoming more evident to the point that, given the uncertainties that surround the use of the model, it should not be used for estimating the return on equity.

In this revised proposal, we do not propose to use the FFM model alone to estimate the return on equity. We consider that the FFM is one relevant model and that FFM estimates of the required return on equity for the should be considered along with estimates of

[367] Attachment 7.05 - Letter from Professor Bruce Grundy to Justin De Lorenzo, 9 January 2015, p. 3.

[368] Attachment 7.05 - Letter from Professor Bruce Grundy to Justin De Lorenzo, 9 January 2015, pp. 3-4.

[369] Attachment 7.04 - SFG, The required return on equity: Initial review of the AER draft decisions, January 2015.

the required return on equity from the SL CAPM, the Black CAPM and the DGM to develop a reasonable range for the allowed return on equity.

In support of this position, we note that far from weaknesses in the FFM becoming recently evident, the strength of the FFM has become recently evident through recognition by the Nobel Prize Committee for Economics of its contribution to modern finance. We also note that there is a breadth of academic literature demonstrating that the FFM improves the predictability of stock returns and that a number of market practitioners such as the well-respected fund manager, Morningstar, consider the FFM reliable enough to use in practice.

DGM estimates

The AER's draft decision considers estimates of the MRP using the DGM. As discussed above, we consider that this is the internally consistent approach that should be followed when using a short-term averaging period to estimate the risk free rate within the SL CAPM. However, the AER's draft decision only has regard to the DGM based estimates of the expected return on the market. We consider that this approach does not have sufficient regard to DGM based estimates of the required return on equity for a benchmark efficient energy network firm.

As noted by the AER's consultants, McKenzie and Partington, the DGM is reported as the second most popular model used by regulators and the most widely used model for estimating the implied cost of equity from valuation models. We also note evidence from Professor Bruce Grundy, which indicates that dividend discount models are widely used by corporations to determine their cost of capital.[370]

The AER's draft decision states that DGM estimates of the required return on equity are not suitable for any regulatory use for the following reasons:

- The model 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 input errors.
- The models are highly sensitive to changes in the risk free rate.
- The models may generate volatile and conflicting results.

We note that all financial models for estimating the allowed return on equity are sensitive to input assumptions and potential input errors. These factors affect the AER's foundation model the SL CAPM, which can be seen from the sensitivity of the return on equity to the estimate of equity beta. The AER's range for equity beta is wide, 0.4 to 0.7. As demonstrated in SFG's attached report on the cost of equity, the estimated cost of equity is significantly different if an equity beta of 0.4 is adopted compared to when an equity beta of 0.7 is adopted. Furthermore, given the statistical uncertainty around the estimation of beta within Australia, it is also likely that the AER's implementation of the SL CAPM is highly sensitive to potential input errors in its estimate of equity beta. However, rather than ignore estimates of the cost of equity using the SL CAPM, the AER applies judgment to arrive at its estimate. Therefore, we do not consider it appropriate for the AER to disregard estimates of the firm-specific return on equity from the DGM on the basis of sensitivities that equally affect estimates from the SL CAPM.

With regard to sensitivity in changes to the risk free rate, we note that the AER's implementation of the SL CAPM is highly sensitive to changes in the risk free rate due to the internal inconsistency with which estimates of the risk free rate and the MRP. In contrast to this, changes in the risk free rate tend to be offset by changes in the MRP using the DGM. This results in estimates of the return on equity using the DGM being more stable over time compared with the AER's implementation of the SL CAPM, a point which has been recognized by the AER itself.[371]

The AER states that DGM based estimates of the cost of equity may generate volatile and conflicting results. As noted by SFG, the fact that some DGM based estimates of the required return on equity produce volatile and implausible results does not mean that all DGM based estimates of the required return on equity do.[372] SFG have produced the following updated estimates of the required return on equity for the benchmark efficient energy network firm using the DGM:

- SFG estimate a required return on equity of 10.9% using its construction of the DGM.

We consider that it is important to consider all evidence and try to improve the statistical robustness of input variables within any financial model. Although uncertainties will remain, more evidence using reasonable assumptions within independent models is

[370] Attachment 7.05 - Letter from Professor Bruce Grundy to Justin De Lorenzo - 9 January 2015.

[371] AER, Explanatory Statement, Rate of return guideline, December 2013, p. 66.

[372] Attachment 7.04 - SFG, Report on the cost of equity for ActewAGL and Networks NSW, January 2015.

more likely to provide a reasonable estimate than one model alone. This approach is consistent with the requirements of clause 6.5.2(e)(1) to consider information from all relevant financial models.

Under-compensation from the AER's allowed return on equity

Table 41 illustrates the under-compensation that would result from the AER's approach to setting the allowed return on equity using currently prevailing rates on 10 year Commonwealth Government bonds, relative our proposed approach, which produces a benchmark efficient allowed return on equity of 10.15%.

Table 41 – Under-compensation from the AER's approach to the return on equity ($ million, nominal)

	2014/15	2015/16	2016/17	2017/18	2018/19	Total
Under-compensation due to the AER's approach to setting the cost of equity	204	213	224	234	243	**1,118**

Note: This is based on an allowed return on equity under the AER's approach of 7.38% (using annualized yields on 10 year CGS over the 20 days to 14 January 2015) compared to our proposed return on equity of 10.15%.

Equity raising costs

In this revised proposal we maintain our initial proposal values for the various components of equity raising costs as outlined in the revised proposal post-tax revenue model/s (see Attachments 4.08 and 4.09).

7.3 Value of imputation credits

The National Electricity Rules (NER) 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.[373] Ausgrid 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, as well as past regulatory practice, and previous decisions of the Australian Competition Tribunal (Tribunal).

In order to promote the National Electricity Objective (NEO), the estimate of gamma must reflect the value that equity-holders place on imputation 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 in determining on 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, electricity network 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. The AER's method involves the following critical 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 NER;
- the AER incorrectly uses equity ownership rates as direct evidence of the value of distributed credits (theta). 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;
- 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;

[373] NER, clause 6.5.3.

- 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 Ausgrid. 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 Ausgrid's original proposal. 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. Our revised proposal position on gamma is set out in Attachment 7.07 - Ausgrid's revised proposal on gamma. We also note that we have requested SFG to provide further analysis in response to the AER's draft decision on gamma, which was not able to be completed in time to submit with this revised proposal but will be submitted at the earliest possible date prior to the close of submissions on the AER's draft decision, 13 February 2015. The substance of issues to be raised in the SFG report is covered in the attached response to the AER's draft decision on gamma.

8. Alternative Control Services

Ausgrid submitted prices that reflect the efficient costs of providing our public lighting, ancillary network (or non-routine) services and elements of our metering services. We proposed public lighting prices using a methodology similar to that developed by the AER last period and our proposed metering prices are based on the metering service provided to the customer.

In the Framework and Approach paper, the AER classified public lighting, metering and ancillary network services as alternative control services. The classification of these services as alternative control services results in customers receiving an individual price for the service (or category of service) rather than the costs being bundled as part of a network charge. Accordingly, in our initial proposal, we set out our proposed prices for alternative control services. This chapter provides our response to the AER's decision on each element of our alternative control services proposal.

Public lighting – The AER has largely accepted our proposed public lighting capital prices, however a significant reduction in operating revenue is being proposed. We do not agree with the AER's conclusions which underpin the proposed reduction in revenue. Our response is set out in Section 8.1 of this chapter.

Metering services – The AER did not accept our proposed charges for annual metering services, new or upgraded connections, and the exit fee. The AER also made significant reductions in our proposed prices for metering services based on its conclusions that our replacement and operating costs were not prudent or efficient. The AER also did not approve administrative costs incurred to process a customer transfer. We do not agree that our proposed metering prices did not reflect an efficient and prudent forecast of our costs. Our response is set out in Section 8.2 of this chapter

Ancillary services – The AER made substantial reductions to some of our proposed prices for ancillary services. The AER considered that our labour costs were high, overheads were significant and that we had over-estimated the time taken to complete a service. Furthermore, the AER misinterpreted the structure and operation of several of our service fees and this has caused misalignment between the draft decision and our initial proposal. As such, we disagree with the AER's assessment and have not revised our proposal in this regard. Our response is set out in Section 8.3 of this chapter.

In addition to the matters set out below. we also have made consequential amendments to our initial proposal for alternative control services to incorporate revisions to our proposed allowed rate of return set out in Chapter 7 of this document.

8.1 Public lighting

In our initial proposal, we used a methodology similar to that developed by the AER in the previous period to develop our proposed public lighting prices. We considered the capital, operating and implementation costs of providing elements of our service and proposed changes to better reflect the costs associated with providing this service. This had a minimal impact to pre and post 2009 capital charges however did increase opex charges by 25%. This increase was mainly due to the amount of customer initiated spot repairs. Beyond this initial step change, Ausgrid proposed to maintain street lighting charges to CPI.

In its draft decision, the AER largely accepted our pre and post 2009 capital charges with the exception of a reduced WACC. However the AER is proposing to not only reject our proposed increase in opex charges but reduce revenue from its existing level by 20%. This level of operational revenue will reduce the level of service that Ausgrid can provide its public lighting customers as well as reduce Ausgrid's ability to maintain the public lighting network safely and to the standards required by AS1158 – Lighting for roads and public spaces and the NSW public lighting code.

In reducing the operational charges the AER noted that:

- A four year bulk lamp replacement (BLR) program should be adopted for all lamps instead of the proposed three year.
- An acceptable range of lamp failure rates is between 4 and 6 % per annum. These failure rates were arrived at using manufacturers' lamp failure data, taking into account that observed failure rates can often be higher in the field than what is claimed by manufacturers.
- Ausgrid's time to repair is considered inefficient at 45.4 minutes and that 31.7 minutes including travel time is considered efficient.

The AER's draft determination states that Ausgrid shall move to a four year BLR for all lamp types. In making its decision, the AER noted that a three year BLR is not considered efficient "given the expected life of lamps and technological advancements that are improving lamps life". The AER also noted that "different bulk lamp replacement cycles could increase the costs due to a reduction in economy of scale having to work different cycle times within the same geographical area".

Ausgrid agree that there have been significant advancements in lamp technology, particularly over the 2009-14 regulatory period and Ausgrid has moved to long life lamps as a standard lamp replacement where this technology is available. However, it is important to note that while Ausgrid has installed long life lamps in 190,000 luminaires since 2011, there still remain three lamps types that are predominant on Ausgrid's network, namely 250W Mercury Vapour, 400W Mercury Vapour and 18W tubular fluorescent lamps which are not suitable for a four year BLR. Ausgrid's initial proposal detailed the technical details as to why they are not suitable in Attachment 8.12, Appendix B.

Ausgrid has approximately 41,000 of these luminaires remaining on our network that need to be completely replaced (in order to install long life lamps) before a four year BLR would be technically and financially viable. While Ausgrid has programs in place to achieve this, they have stalled as more customers are requesting LED street lights to be deployed. For example, councils have made comments in response to Public Lighting tender documentation to the effect of:

> *We see no substantive basis for the continued purchase of HID and fluorescent luminaires to still be purchased for up to 5 years as outlined in the draft tender. LED street lighting has become the dominant lighting technology in recent years because of its proven reliability, energy efficiency, optical control, high quality white lighting and, perhaps most importantly, because it is now widely accepted as having the lowest total cost of ownership. Councils expect that, on a lowest total cost of ownership basis, all lighting categories in the tender will go LED consistent with current best practice*

Ausgrid has been progressively rolling out LED technology since 2013. For example we deployed approximately 10,500 category P (residential) LED street lights, many of which have replaced 18W tubular fluorescent luminaires and we note that this is the largest roll out in Australia. However, procurement of category V (main road) LED street lights is more problematic as until recently these were not economically and technically viable to deploy. Nevertheless, with advances in technology, we are currently in the process of sourcing a suitable category V LED street light which if economically and technically viable may then be used to replace the necessary luminaires to move to a four year BLR program.

Until Ausgrid is in a position to move to a four year BLR program the cost associated with a three year program should be able to be recovered. This is because a move to a four year BLR will cause many of our lighting installations to be non-compliant in the fourth year due to the levels dropping below those specified in the relevant Australian Standards (AS1158.1.1 and AS1158.3.1). This has the potential to put the safety of our customers and the community at risk. Ausgrid therefore re-submits its operational expenditure model based on a three year BLR.

Ausgrid agrees that the AER's lamp failure rates are indicative of what Ausgrid experience in repairs initiated by lamp failures. However, Ausgrid's proposal was not based on lamp failure rates in isolation, but the number of customer initiated spot repairs. A distinction needs to be made between lamp failure rates and the defect rates of luminaires owing to a number of different failure modes. Ausgrid refers to these as call out rates. Ausgrid estimates that lamp failures make up 42% of the total number of customer initiated spot repairs, whereas other failure modes such as blown fuses, faulty street lighting control points, cracked or damaged visors, wiring issues and scenarios where no fault is found make up the remaining 58%. The AER has not included any allowance in their draft determination for recovery of costs associated with failure modes other than lamps. Allowing only for the cost recovery of failures due to lamps could result in up to 20,000 failures going unrepaired each year. This situation also has the potential to put the safety of our customers and the community at risk due to substandard lighting levels. We submit that the AER should accept Ausgrid's original failure rates, having regard to the above failure modes and the potential consequences of unrectified defects.

Ausgrid does not agree with the AER that the time taken to repair is inefficient. Included in our initial regulatory proposal was a detailed time and motion study which determined the amount of time required for luminaire spot repairs. We again highlight this study and argue that an average of 20 minutes travel time between jobs is an appropriate amount of time for these types of repairs.

Ausgrid also notes the AER's revised allowed rate of return. Ausgrid does not accept the AER's draft determination and explains our reasons in Chapter 7.

We also note the AER's concerns on Ausgrid's confidentiality claims. Ausgrid's concerns over disclosing confidential information such as suppliers and service providers pricing were made clear in our submission to the AER on 12 August 2014. Ausgrid believes that the AER's stated objectives in its initial disclosure notice dated 15 July 2014 can be achieved without the disclosure such information. Ausgrid has structured its regulatory proposal, to the extent possible, to provide as much information on a non-confidential basis. We have published working pricing models and all underlying assumptions that does not include any third party commercial in confidence information. A customer would be able to use these models and apply input prices that they think are efficient to calculate the public lighting charges.

Since Ausgrid's submission on the initial disclosure notice the AER is yet to make a decision on whether to disclose this information or not. The AER stated that "Ausgrid has refused to publically release crucial information to councils" and that this is "hindering the ability of stakeholders to make informed submissions". On that basis the AER has indicated that the draft determination is a place holder determination based only on the public information submitted. Ausgrid submits that we have followed the confidentiality guidelines set by the AER and that the decision to disclose this information or not rests with the AER.

Further, we note the AER's concerns and submissions from councils regarding the relationship we have with our customers. We undertook an extensive consultation process with our councils and found that they:

- accepted our commitment to cap prices at CPI;
- wanted service levels to be maintained according to the NSW Public Lighting Code; and
- considered LED technology an important future state to work towards.

We will continue to engage with our customers with any questions or assistance they require in this regard.

Ausgrid further details our position on the draft determination in Attachment 8.01 and has updated its pricing models and component price lists in Attachments 8.02 and 8.03 respectively.

8.2 Metering services

Our initial proposal presented prices for metering services based on the required metering system functionality, the cost of service provision and the subsequent services our customers are receiving. These prices incorporate the type of meter hardware installed along with the associated meter reading and meter data processing costs. As would be expected, the cost of metering services increases with the complexity of the meter, with the benefit of increased functionality and improved energy consumption data. Ausgrid has developed cost reflective prices by examining our historical expenditure to determine the drivers of metering costs. This included recovering the costs of existing meters, new meters, operating and replacement costs.

Ausgrid's revised response to the AER Draft Determination is summarised as follows:

- ***Structure of charges*** - Accepted our proposed structure of metering charges, that is, to charge an upfront fee representative of the upfront capital cost for new and upgraded connections and an annual charge that varies by tariff class;
- ***Capital Expenditure*** - Accepted the capital expenditure revenue building block approach, but did not accept the metering capital expenditure costs overall on the basis of the metering hardware unit costs (although did accept constituent volumes and labour unit costs) - further supporting analysis for Ausgrid's meter hardware costs is provided;
- ***Operating Expenditure*** - Did not accept forecast metering operating expenditure based on benchmarking and a base year substitution - we have provided additional explanation validating our initial approach and we have remodelled the operating expenditure in Attachment 8.05;
- ***Metering RAB*** - Did not accept the Metering Regulated Asset Base (RAB) calculation - we have accepted the AER's revised Metering RAB;
- ***Meter Exit Fee*** - Did not accept our proposal for stranded meter asset cost recovery (that is, through an exit fee) and did not consider there was adequate justification for the administrative cost component of the exit fee - we have accepted the AER's approach to recovering residual capital costs through Standard Control Services and the recovery of the administrating fee as alternative control services. We provide additional information in support of recovering administrative costs of exits; and
- ***Control Mechanism*** - Accepted the control mechanism approach of price caps on individual services, but did not accept Ausgrid's proposed caps. Further, the AER proposed an alternative approach to the calculation of CPI. We have provided clarification on how the price cap should be applied.

In the subsections that follow we address the issues raised by the AER in their Draft Determination, presenting our reasons where we do not accept their decisions but also confirming where we accept the AER's findings. We also present our updated and revised metering prices and justification for these changes, with the revised modelling of revenue and prices found in Attachment 8.06 and Attachment 8.07 respectively.

Attachment 8.04 provides further detail of our revised metering proposal along with more comprehensive responses to the AER's Draft Determination

Proposed structure of metering charges

Ausgrid's high level structure of meter charges was accepted by the AER. This consists of:

- Charging upfront for new and upgraded meter connections.
- An annual charge that varies by tariff class.

We maintain this approach in our revised proposal, and have provided further detail in response to the AER's areas of concern. In the below sections we provide details of the 'Meter Transfer Fee' to replace the initially proposed Exit Fee.

Forecast metering capital expenditure

The AER accepted the volumne and labour unit costs components of Ausgrid's forecast metering capital expenditure, but did not accept Ausgrid's meter hardward unit cost.

The AER proposes a reduction in the materials component of metering capex on the basis that Ausgrid's meter hardware unit costs are not efficient. This had an overall impact of reducing the proposed metering capex by $3.2 million ($ nominal).

Below, Ausgrid provides detailed justification of the meter hardware prices to complement the AER accepted components of metering capital. Based on the below justification, Ausgrid maintains its initial proposal on metering capital.

AER Proposed Hardware Prices – Arbitrary Meter Hardware Substitutions

The AER substituted the lowest end of the determined market rate range as the efficient hardware price and adjusted the forecast capital expenditure accordingly. The AER has drawn this conclusion based on the assumption that ongoing procurement improvements by NNSW will lead to the lowest market price, with little regard for the prudent selection of meter hardware. With the factors included below and in Attachment 8.04, Ausgrid's inclusion in NNSW joint sourcing will not lead to procurement at Marsden Jacobs assessed lowest level hardware pricing.

The AER's substitute meter hardware unit cost is not supported by the advice received by the AER from its consultant (Marsden Jacobs Associates) who stated:

> *that metering hardware costs proposed by each of the businesses should be accepted where the proposed costs are below Marsden Jacob's recommended maximum.*

The report goes on to state:

> *Where the rates are above the current market rates and Marsden Jacob's maximum proposed rates, we recommend the allowable costs be capped at Marsden Jacob's recommended rate for the particular category and type of meter"*[374] .

Four of the six Ausgrid proposed meter hardware prices fell well within the Marsden Jacob Associates (MJA) maximums[375]:

- Accumulation 3 phase Direct Connected - Ausgrid proposed $96.09 against MJA maximum of $100.00
- Interval 1 phase Direct Connected - Ausgrid proposed $88.06 against MJA maximum of $100.00
- Interval 1 phase Dual Element Direct Connected - Ausgrid proposed $147.26 against MJA maximum of $150.00
- Interval 3 phase Direct Connected - Ausgrid proposed $202.00 against MJA maximum of $220.00.

Two of the six Ausgrid proposed meter hardware prices were outside the Marsden Jacob Associates maximums[376]

- Single Phase Direct Connected Accumulation Meter which exceeds the maximum by $0.06 ($23.06 versus the $23.00 maximum)
- Three Phase, Current transformer connected interval meter ($519.00 versus the $400.00 maximum). These represent a comparatively small volume of meters purchased. The price is inclusive of an onboard modem which aligns with Ausgrid's solution for such sites and therefore justifies Ausgrid's proposed price ($519.00).

AER proposed hardware prices – prudent selection of meter hardware

Ausgrid's position remains firm in relation to purchasing meter hardware as originally proposed. Ausgrid considers a prudent operator does not select metering equipment based on up-front price alone. The up-front meter price is only a small fraction of the cost of a metering installation over the whole-of-life and most significantly, the value of the electrical energy that flows through the meter. For this reason, issues of safety, reliability, accuracy, efficiency of reading, ease of installation, functionality, compliance performance and logistics are taken into account in the procurement process.

As an example, some metering equipment that complies with the NER and related requirements are not necessarily the most efficient to install. Meters that are simpler to install not only save labour time but are significant for the replacement of metering equipment on older meter boards that contain asbestos, where matching mounting holes eliminates drilling of panels and exposing installers to asbestos dust.

Ausgrid maintains the position on the above proposed selection of metering hardware as Ausgrid's forecast of material unit costs reasonably reflect the efficient cost of a prudent operator. As such, the revised metering capital expenditure is summarised below.

Table 42 – Forecast direct metering capex ($ million, 2013/14)

Capex category	2014/15	2015/16	2016/17	2017/18	2018/19	Total
New and upgrade connections	4.92	5.28	8.54	8.47	5.11	32.32
Reactive replacement	5.16	5.16	5.05	5.04	5.08	25.47
Proactive replacement	4.32	7.74	13.59	13.55	13.71	52.91
Total	**14.40**	**18.18**	**27.18**	**27.05**	**23.90**	**110.70**

Note: Numbers may not add due to rounding.

In addition to the forecast capex above, direct metering IT capex and indirect non-system capex is allocated to Type 5 and 6 metering across 2015-19 through Ausgrid's CAM. To calculate the capital cost, we applied a rate of return of 8.85%, consistent with that used for standard control services. Further details of Ausgrid's revised metering capex, including the impacts of new cost escalators can be found in Attachment 8.04.

[374] Marsden Jacob report, table 15, Summary of Proposed Meter Costs, p. 17.

[375] Marsden Jacob report, table 15, Summary of Proposed Meter Costs

[376] Marsden Jacob report, table 15, Summary of Proposed Meter Costs

Forecast metering operating expenditure

The AER substituted Ausgrid's proposed $143.4 million ($ nominal) operating expenditure with a lower figure of $119.1 million ($ nominal). The AER determined this figure predominantly through a lower annual starting point of $23.3 million ($ nominal) in 2014/15 justified by referencing the average operational expenditure for 2009-13 ($24.8 million ($ nominal per annum)) and referencing Energex's per customer benchmark metering cost of $14 per customer per annum.

The AER commented that:

> *We acknowledge that there may be exogenous factors other than customer density which explain why Ausgrid's operating expenditure per customer is higher than Energex's.*

Ausgrid notes that the AER used Energex as a relevant comparator for benchmarking purposes, however the AER have overlooked a fundamental and significant difference in the provision of Ausgrid's metering services in comparison to Energex's. Ausgrid's metering population includes a significant proportion of Type 5 meters (30% of total metering installations), which are manually read interval meters. Energex has not historically operated Type 5 interval meters and as at 30 June 2014, has zero meters operating as Type 5 meters[377]. Furthermore, Ausgrid's changes in operational costs have been impacted by the increase in the Type 5 meter population (and its associated benefits) since 2008/09.

For these reasons, we do not accept the comparison and subsequent benchmarking with Energex as it is unreasonable and inconsistent and any decision based on this approach would be based on a material error. Ausgrid believes that with the historic change in its metering population demographic prior to 2012/13, using the base year of 2012/13 is the most appropriate for an operating expenditure starting base.

The total metering operational forecast costs were prepared by applying a top down approach to the base year. This detailed top down approach then analysed all internal orders and segregated costs by:

- alternative control services - Type 5 metering;
- alternative control services - Type 6 metering;
- standard control services - bulk supply point related metering services, Type 7 metering; and
- ancillary network services (under alternative control services) - metering

The costs relating to special meter reading and meter accuracy testing opex were removed from the historic expenditure. These amounts need to be excluded as they are captured within ANS forecast opex.

Additionally, in its draft decision the AER noted that a negative step change may be required for metering to account for the ANS costs that may be embedded in historical metering opex:

> *"...we consider that Ausgrid should apply a negative step change to account for ancillary metering services, which from 1 July 2015 will be reclassified to ancillary network services and so should, therefore, be excluded from metering operating expenditure allowance. We have not quantified the amount of this negative step change in our draft decision, but will apply it in our final decision."*[378]

Ausgrid can confirm that no reduction is required to the base opex for this reason. The revised metering services forecast opex excludes these costs from the base opex and these costs have been separately included in ancillary network services opex.

Changes to Ausgrid's metering population

The AER have utilised an average of multiple years (2008/09 – 2012/13) to determine a base of Ausgrid's metering operational costs. This approach is not reasonable as Ausgrid's metering population has fundamentally changed since FY2009:

- At the beginning of 2008/09 Ausgrid's metering population consisted of 15% Type 5 and 85% Type 6 installations.
- At the end of FY2013 the metering population consisted of 30% Type 5 and 70% Type 6 installations[379].

This demonstrates Ausgrid's Type 5 metering population proportion has steadily increased throughout the period. To use the average of the period as an indication of the starting point for the future incorrectly distorts the cost. As Type 5 meters attract a higher per unit reading and data processing cost[380] compared to Type 6 meters, the averaging approach does not correctly account for current or future expenditure.

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[377] Energex - 1. Reset RIN Basis of Preparation - October 2014

[378] AER draft decision – Attachment 16: Alternative control services, November 2014, p. 16-43

[379] MBS Query "E61961 - Snapshot of the meter population (installed) on a given date - MIT"

[380] Increased time to read a Type 5 meter reflected in a probe meter reading surcharge and interval meter data validation as per AEMO metrology procedure requirements.

Instead, by assessing the expected proportion of Type 5 and Type 6 installations expected in the 2015-19 period, a correct cost base can be determined. Over the new regulatory period, it is envisaged the proportions between Type 5 and Type 6 will stabilise given the new strategy of like-for-like replacements and new and upgrade meter installations no longer being exclusively Type 5. This is supported by more recent analysis:

- In 2013/14, the Type 5 population continued to grow at a slower rate than previous years;
- Most recent 2014/15 data indicates that even with Ausgrid adopting the new strategy of a Type 6 meter as the default, the Type 5 population is only slowly increasing with the overall Type 5/ Type 6 proportions remaining stable going forward.

As such the 2012/13 base year remains highly representative for future years with efficiencies equal to the increase in Type 5 in 2013/14[381] and future years projected over the coming regulatory period.

Utilising inappropriate benchmark comparison

The AER have referenced the Energex per customer benchmark metering cost of $14 per customer per annum as the mechanism to justify the reduction in Ausgrid's proposed operating expenditure. The Energex benchmark was chosen by the AER because it deems it to be a network with "Ausgrid's characteristics".

The AER has overlooked the fundamental difference in the provision of Ausgrid's metering services in comparison to Energex. Ausgrid's metering population includes a significant proportion of high enablement Type 5 (30% of installations) manually read interval meters whereas Energex has zero Type 5 meters[382] and 100% Type 6 in its meter population.

Once Ausgrid's Type 5[383] costs are separated from this benchmark, a more representative comparison can be made with cost per customer. Referencing customer numbers and operational and maintenance costs quoted in Ausgrid's original submission, the per customer cost for an Ausgrid Type 6 customer is $11.26 ($ nominal), significantly less than the Energex benchmark. This benchmark performance aligns with the average cost of other operators[384].

For this reason, the Energex $14 per customer operating expenditure benchmark is not appropriate to be used to justify the reduction of Ausgrid's total operating expenditure proposal.

It should also be noted that Ausgrid (previously EnergyAustralia) rolled out Type 5 meters to 15-160 MWh p.a. customers during the 2004-09 regulatory period which was approved by IPART. Quoting IPART's 2004-09 Determination:

> *"allowing for expenditure for installing interval meters, the Tribunal notes that EnergyAustralia, in its April 2003 submission, included $46 million of expenditures associated with providing interval meters to large users (>15MWh). EnergyAustralia stated that this expenditure will facilitate tariff reform. As Meritec reviewed this expenditure and found that it was efficient, the Tribunal has allowed it."*[385]

Given that the roll out of Type 5 meters over 15MWh per annum was considered efficient by IPART, and Ausgrid allows customers less than 15 MWh to opt out of Type 5 based tariffs, Ausgrid considers the additional operational cost of Type 5 (as compared to that of the standard Type 6) is justifiable.

Furthermore, the AER has used customer density as a key determinant in its benchmarking analysis[386]. Whilst Ausgrid has demonstrated meeting the benchmark efficient level with Type 6 metering, the AER has assumed that there is a linear relationship between customer density and costs, which is not necessarily correct. This is exemplified by high density installations such as in the CBD where traffic congestion, inaccessible parking near work sites and more difficult access to customers' sites can result in a high cost per customer. Factors such as these have not been considered by the AER in determining efficient levels of meter operating expenditure through benchmarking.

Ausgrid's revised metering operating expenditure

Ausgrid has retained the 2012/13 base year approach to develop the opex forecast as per the original proposal, with updates only driven by revised cost escalators (labour, materials, contracted services and labour hire). The updated forecast is shown in Table 43, with the complete modelling of revised metering operating expenditure provided in Attachment 8.05.

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[381] It should be noted that the AER used an incorrect figure for Ausgrid's 2013/14 estimated Metering Opex ($18.6 million, $ nominal). This figure excluded direct metering IT costs and overheads. This was presented in AER Draft Determination Attachment 16, Figure 166-4 p.16-41.

[382] 1. Energex - 1. Reset RIN Basis of Preparation - October 2014

[383] It should be noted that Type 5 meters whilst requiring a higher annual per customer operating expenditure (of $31.54), they benefit the market with the supply interval data to the National Electricity Market, supporting cost reflective tariffs and efficient market settlement. This aligns with the National Electricity Objective.

[384] AER's draft decision - Attachment 16 Figure 166-5, p. 16-42).

[385] IPART Report: Final Report – NSW Electricity Distribution Pricing 2004/05 to 2008/09 – June 2004, p. 37.

[386] AER draft decision - Attachment 16, p. 16-42, 16-43.

Table 43 – Forecast metering opex ($ million, 2013/14)

Opex category		2014/15	2015/16	2016/17	2017/18	2018/19	Total
Metering maintenance	Type 5	3.19	3.23	3.27	3.32	3.36	**16.37**
	Type 6	2.32	2.34	2.37	2.41	2.44	**11.88**
Meter reading	Type 5	3.27	3.31	3.35	3.40	3.44	**16.77**
	Type 6	4.78	4.83	4.89	4.96	5.03	**24.50**
Metering data services	Type 5	3.86	3.90	3.95	4.01	4.06	**19.79**
	Type 6	0.93	0.94	0.96	0.97	0.98	**4.79**
Metering ICT opex	Type 5	3.17	3.19	3.21	3.24	3.26	**16.07**
	Type 6	1.36	1.37	1.38	1.39	1.40	**6.89**
Opex overheads (indirect)	Type 5 and 6	4.43	4.54	4.60	4.66	4.72	**22.95**
Total		**27.32**	**27.66**	**27.99**	**28.35**	**28.69**	**140.01**

Note: Numbers may not add due to rounding.

Based on the information provided throughout the initial proposal and the additional justification above, the AER should accept Ausgrid's revised metering services opex forecast

Opening metering regulatory asset base (RAB)

Ausgrid and the AER have agreed on a number of amendments to Ausgrid's distribution roll forward model. The effect of these amendments is that the opening 2014-15 Metering RAB was adjusted from $260.8 million ($2013/14) initially proposed by Ausgrid to $267.2 million ($2013/14).

Ausgrid has addressed the change to the distribution roll forward model in section 4.2.

Building block approach for revenue requirement

Ausgrid proposed a building block approach to the development of a metering revenue requirement, which was used to develop cost reflective annual meter prices. The AER approved this approach which utilises the AER's template post tax revenue model (PTRM), and therefore we do not propose to deviate from this approach.

To enable this approach, the forecast metering capex is converted into asset classes for the PTRM following a process of global cost escalation, mapping to asset classes and cost allocation (using the cost allocation methodology approved by the AER) of shared non-system capital expenditure (such as fleet, IT systems and property). This process is reliant on enterprise systems.

Ausgrid acknowledges that the AER was unable to model the draft determination metering capex using Ausgrid's IT enterprise systems, and therefore used a pro-rata approach in place of our IT enterprise system. Despite this, the AER informed Ausgrid that the incorrect total capital expenditure was utilised[387]. As such, Ausgrid does not accept the AER's draft determination metering PTRM[388] and subsequent metering charges model.

Ausgrid's revised metering PTRM revenues for recovery through annual charges, impacted by the revisions to forecast metering capex and opex, are presented in Table 44, with the revised model provided in Attachment 8.06.

[387] AER correspondence with Ausgrid, Ausgrid AER 001, 12 December 2014

[388] AER Draft decision Ausgrid distribution determination - Ausgrid 2014 - PTRM - Meters - November 2014.XLSX

Table 44 – Ausgrid's revised metering building block revenue requirements ($ million, nominal)

Metering services	2014/15	2015/16	2016/17	2017/18	2018/19
Return on capital	23.64	23.80	23.63	24.01	24.43
Return of capital	20.46	23.03	25.44	21.63	20.94
Opex	28.01	29.06	30.14	31.29	32.46
Benchmark tax	2.05	3.87	5.96	5.62	3.76
Revenue Requirement	**74.16**	**79.76**	**85.16**	**82.54**	**81.59**

Note: Numbers may not add due to rounding.

Customer exits – meter transfer fee

Ausgrid's fee for customer exits originally comprised of two components, the stranded asset cost and the administration cost. The AER considers that stranded asset costs should be recovered via standard control services rather than as part of an exit fee and also that Ausgrid did not adequately justify the administration cost element.

For the revised proposal, Ausgrid recommends a new 'meter transfer fee' to account for the administration costs only to be recovered through alternative control services.

The AER rejected our proposed approach and prices on the basis that an exit fee would create a barrier to competition. It should be noted that the recovery of these costs were not addressed in the AER's stage 1 framework and approach paper[389], and therefore Ausgrid took steps to develop an approach for the Regulatory Proposal in May 2014.

The AER has proposed that a new standard control service be created to allow DNSPs to recoup the stranded asset costs created by competition at the time a customer obtains an alternate metering service provider. As noted in Chapter 3, Ausgrid does not accept the need for classification of this as a separate service. However, Ausgrid accepts the AER's position in relation to the stranded asset costs being recovered through standard control services. This approach is detailed in Attachment 9.01 as part of the annual adjustment (B-factor).

In relation to a new meter transfer fee, the AER states, "We maintained the classification and control mechanism for the administration cost component as an alternative control service with a price cap for the individual service"[390]. Ausgrid accepts the AER's position in relation to the meter transfer fee (administration cost) being recovered through alternative control services.

The AER rejected Ausgrid's proposed administration cost level of $36 ($ nominal) stating "…as Ausgrid did not adequately demonstrate they will incur incremental administrative costs, we are led to reject an exit fee based on administrative costs"[391]. As a result, Ausgrid has undertaken further analysis to justify and substantiate the proposed Meter Transfer cost, with details available in Attachment 8.04. The revised modelling of the meter transfer fee is provided in Attachment 8.07.

Furthermore, Ausgrid's proposed meter transfer fee is in-line with the maximum fee stated in an independent report commissioned by the AER[392], and thus meets the AER's criteria of being "efficient and reasonable". Therefore, Ausgrid will not be making any revisions to the proposed meter transfer fee of $36 (nominal) in the revised proposal.

Annual prices

Ausgrid proposed a single set of annual prices for all new and existing customers, and has retained this approach as part of the revised proposal. Ausgrid reviewed the AER's preference for charging new and upgrade customers differently to existing customers, but found this approach unjustified.

Our modelling resulted in a material difference between new and existing customers each year. As a result, Ausgrid maintains the position of a single set of annual charges applicable to all Type 5 and 6 metering customers.

The revised prices can be found in Table 45, with the complete price modelling provided in Attachment 8.07.

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389 AER draft decision - Attachment 16 Alternative Control Services, November 2014, p. 16-35

390 AER draft decision - Attachment 16 Alternative Control Services, November 2014, p. 16-36

391 AER draft decision - Attachment 16 Alternative Control Services, November 2014, p. 16-48

392 The AER engaged Marsden Jacobs Associates to prepare Provision of advice in relation to Alternative Control Services – PUBLIC VERSION, October 2014, p. 20.

Table 45 – Revised indicative prices for metering services (c/day, nominal)

Tariff Name	2014/15	2015/16	2016/17	2017/18	2018/19
Residential inclining block	9.23	9.50	9.82	10.13	10.47
Residential ToU	15.24	15.65	16.16	16.63	17.14
Controlled load	3.70	3.82	3.96	4.10	4.24
Small business inclining block	12.59	12.97	13.42	13.86	14.33
Small business ToU	14.85	15.25	15.74	16.20	16.69
LV 40-160MWh ToU	23.53	24.14	24.90	25.61	26.36
Generator tariff	4.42	4.56	4.72	4.88	5.04

Note: The prices shown for 2014/15 represent Ausgrid's proposed cost-reflective prices, not the actual prices charged to customers for this year. The actual prices charged for 2014/15 are included in the general network charges.

Upfront new & upgrade charge

As addressed in the sections above, the AER made a decision to utilise the lowest meter hardware unit rates of the benchmark range which impacted the decision on meter capital expenditure as well as the upfront charges. Ausgrid does not accept the AER's Draft Decision prices for the reasons set out above.

The following upfront charges have been updated to account for new escalators and the revised weighted average cost of capital (WACC). The new prices are shown in Table 46 with the revised modelling provided in Attachment 8.07.

Table 46 – Revised indicative prices for meter hardware ($nominal)

Tariff Name	2014/15	2015/16	2016/17	2017/18	2018/19
Single Phase Single Element Two Wire Direct Connected Accumulation Watt-hour Meter	47.65	49.05	50.62	52.31	54.01
Three Phase Single Element Four Wire Direct Connected Accumulation Watt-hour Meter	123.84	127.15	130.67	134.36	138.11
Single Phase Single Element Two Wire Direct Connected Interval Watt-hour Meter	116.09	119.20	122.53	126.01	129.55
Single Phase Dual Element Two Wire Direct Connected Interval Watt-hour Meter	177.22	181.86	186.76	191.85	197.03
Three Phase Single Element Four Wire Direct Connected Interval Watt-hour Meter	239.60	245.80	252.30	259.02	265.89
Three Phase Single Element CT Connected Interval Watt-hour Meter	578.59	593.27	608.45	624.08	640.08

Note: The prices shown for 2014/15 represent Ausgrid's proposed cost-reflective prices, not the actual prices charged to customers for this year. The actual prices charged for 2014/15 are included in the general network charges.

Control Mechanism

Ausgrid accepts the AER's control mechanism to apply a cap on fee based metering services, although does not accept an X factor of zero to apply (i.e., no further increase of prices other than CPI). We consider that labour cost escalation (which is the main driver of prices) and other escalation for contracted services, labour hire etc., should apply in addition to the CPI increase for metering services to ensure that charges continue to be cost reflective.

Ausgrid notes that an X-factor has been allowed in the draft decision for ANS fees to allow for the AER's draft decision on real cost escalators. As such, Ausgrid does not understand why the X-factor has been disallowed for metering.

Ausgrid seeks to clarify that individual price caps should apply to individual prices (i.e., separate price caps for upfront new and upgrade charges, annual prices and meter transfer fee, and individual prices within them). This is driven by differences in the construction of fees and charges; for instance, a high proportion of the upfront new and upgrade charges related to meter hardware costs in contrast to the meter transfer fee which is predominantly labour costs.

The proposed revised price caps are presented in Attachment 8.04, as well as Ausgrid's position with respect to the calculation of CPI, which is in line with the CPI calculation for distribution standard control services.

8.3 Ancillary network services

Ancillary network services (ANS) are non-routine services provided to individual customers on an 'as needs' basis.

Ausgrid's original proposal included cost reflective prices for each ancillary service as required by the AER's approach to classification and control for these services. These services included new services identified by the AER's Stage 1 Framework and Approach including the re-classification of services (from standard control services) formerly known as 'miscellaneous and monopoly' fees as defined in the AER's framework and approach. The re-classified services had been set historically by IPART and carried forward over the past regulatory periods. The prices proposed by Ausgrid for the 2014-19 period were intended to eliminate the cross-subsidisation of these specific activities by all customers through standard control services.

During the framework and approach consultation process the NSW DNSP's expressed concerns with the AER's proposed approach. Whilst a cross-subsidy existed, we were of the view that an immediate transition to the new classification would represent a significant impact to ANS customers.

> *"The NSW DNSPs flagged in their responses to the Consultation Paper that the current regulated schedule of fees and rates is not cost-reflective and that the potential price increases required to ensure cost reflectivity are likely to cause customer satisfaction issues. There are also likely to be discrepancies in pricing across the three NSW DNSPs given the different characteristics of the networks."*[393]

Ausgrid shared similar concerns raised by the other NSW DNSPs, that the immediate shift to cost reflective pricing would lead to price increases in the order of hundreds of percent for some services and customers now being charged for new service fees that had been previously absorbed by operational expenditure or capitalised. This was due in large to the approach to pricing adopted by previous regulatory decisions that constrained the pricing of ANS to only CPI increases for over a decade, despite known real cost movements occurring over that time that were inherently reallocated by those decisions into the general network charges.

Despite this, the services were re-classified and thus Ausgrid submitted cost-reflective prices that represented the efficient cost to provide these services. No alternative options were provided to Ausgrid to transition customers to the new prices. In giving effect to the framework and approach there will be instances of large increases, but equally there are instances of significant decreases such as the site establishment fee.

AER draft determination

The AER's draft decision was to not accept some elements of our proposed prices in the draft determination as it considered they exceeded the efficient cost of providing these services, although the AER did accept the need to provide cost-reflective prices as described above:

> *"Our draft decision is to accept the step increase in charges for ancillary network services from those during 2009–14. This is because we have reclassified quoted and fee based activities from standard control services to alternative control services. The result is that customers choosing these services now bear the full costs of their provision rather than being subsidised by all electricity users. Nonetheless, customers will receive as small offsetting reduction in Ausgrid's standard control services revenue (and therefore tariffs) to compensate for this."*[394]

In reviewing the detailed draft decision pertaining to alternative control services in Attachment 16 of its draft decision the AER have rejected Ausgrid's proposed schedule of prices. This was based on advice from the AER's consultant, Marsden Jacobs Associates, which suggested our overheads and labour rates are inefficient:

> *"Our draft decision is to not approve Ausgrid's proposed fees for ancillary network services. We consider the proposed fees are higher than fees based on maximum benchmark labour rates and overheads which we consider efficient for providing ancillary network services."*[395]

Ausgrid has not revised the labour rates that were originally submitted to the AER in May 2014, and is only proposing to update ANS prices with most up-to-date cost escalators, with the price models for meter-related ANS provided in Attachment 8.09, and the models for connection-related ANS provided in Attachment 8.10. We do not consider revisions are required to address the matters raised by the AER in its draft decision for the following reasons:

- Ausgrid's raw internal labour rates are substantiated by actual information and are determined by the Enterprise Bargaining Agreement 2012 (with escalation factors applied to labour rates to bring them up to $nominal) and we consider they represent a cost-reflective and efficient price.
- The Ausgrid models that were modified by the AER to determine the AER draft decision for the ANS fees and rates are in 2012/13 dollar terms and not escalated to 2014/15. The AER modified models have changed the escalation factors for the base year to be 2014/15 fiscal year. As Ausgrid utilised 2012/13 as the base year for these models, this would leave the labour

[393] NSW DNSPs' Response to the AER's Preliminary Framework and Approach Paper, 17 August 2012, Pg 31.

[394] AER draft decision – Overview 2015–16 to 2018–19, November 2014, pg 63

[395] AER draft decision – Attachment 16: Alternative Control Services, November 2014, pg 13

rates two years behind in CPI escalations. The escalations applied to raw labour rates are determined by the Enterprise Bargaining Agreement from 2012 and are the most correct figures to be used.

- Ausgrid's methodology for determining service fee prices is prudent, efficient and robust.
- Ausgrid's overheads and oncosts were calculated and applied in accordance with the CAM approved by the AER.
- The assessed time to undertake specific jobs have been analysed in detail, and as an input into our proposed efficient prices, these are reasonable and justifiable.
- There are examples of unreasonable outcomes that are produced by relying significantly on benchmarking analysis such as the under recovery of the cost of delivering these services. These outcomes are further invalidated as the AER has made errors in the development of the draft decision. These are detailed in Attachment 8.08.

These issues are discussed in further detail in the following sections, as well as a clarification to Ausgrid's position in terms of the applicable control mechanism for fee based services and quoted services.

Labour costs

As discussed above, the AER has made significant reductions to our proposed ANS fees utilising benchmarking analysis of the labour costs provided by Marsden Jacobs. Moreover, the AER made the reductions by substituting Ausgrid's labour rates with labour costs below Marsden Jacob's identified costs[396]. Whilst we acknowledge that benchmarking is an available assessment tool we consider it to be of limited value in forecasting practical and efficient service delivery. The Marsden Jacobs analysis suggests Ausgrid is above the maximum allowable benchmark labour rates (inclusive of on-costs and overheads):

> *"We reviewed Ausgrid's proposed fees for ancillary network services and the methodologies used by Ausgrid to calculate these fees. Based on our analysis of Ausgrid's proposed methodologies, the main concerns are the cost inputs to the methodologies. Where there are inefficiencies in actual historical costs these will be carried through in the derivation of proposed fees."*[397]

In Chapter 6 we have outlined the limitations of benchmarking. In this regard, Ausgrid contests that there are issues concerning the accuracy and reliability of the AER's approach to benchmarking which is demonstrated by the spectrum of results benchmarking can produce. We do not consider the techniques are sufficiently refined enough to be relied upon to such a degree. As an example, the application of the Marsden Jacobs analysis ignores the fact that Ausgrid cannot access a national or international labour market. It is not clear if the results are driven by lower labour rates in other states, countries or industries. As such, Ausgrid contests that it cannot obtain the rates as described in the Marsden Jacob analysis based on the local labour rates for the qualifications required by each Ancillary Network Service.

In addition to this, Ausgrid's proposed raw labour rates (excluding on-costs and overheads) that were analysed and benchmarked using the Marsden Jacobs Associates report largely fell within the benchmark labour rate ranges:

As set out in Marsden Jacob's recommended labour rates (Table 166-8), Ausgrid's proposed raw labour rates fell within these ranges, except for administration support and senior engineer. [398]

Therefore this further contributes to the questionable application of benchmarking by the AER to total labour rates, as application of overheads and on-costs to can differ between DNSPs. Ausgrid's on-costs and overheads have been applied using the AER approved CAM. This is discussed further below.

Overhead costs

The overhead factors we applied in developing our prices was derived by applying the AER approved CAM. In rejecting our proposed prices the AER noted our overheads were above the maximum benchmark allowable. Specifically:

> Ausgrid's overhead rate for administration, technical specialist and field worker were above the maximum average overhead recommended by Marsden Jacob for ancillary network services. [399]
>
> *"Marsden Jacob recommends that the average overhead applied for Ancillary Network Services be capped at 65%. The recommendation recognises the fact that ActewAGL and Essential have applied similar overheads rates compared with the much higher rates applied by Ausgrid and Endeavour. The higher rates appear particularly out of line with the rates applied by the Victorian businesses, although the magnitude of the difference appears to indicate a more fundamental difference in the approach to cost allocation. Therefore, our recommended cap of 65% reflects the benchmark established by the two NSW businesses with lower overhead rates.*
>
> *Importantly, we note that the methodology for allocating overheads is provided in the AER's Cost Allocation Methodology. Therefore, while our benchmarking considers the overheads for Ancillary Network Services in isolation, capping the overhead*

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[396] AER draft decision - Attachment 16: Alternative Control Services, November 2014, p. 16-15

[397] AER draft decision - Attachment 16: Alternative Control Services, November 2014, p. 16-23

[398] AER draft decision - Attachment 16: Alternative Control Services, November 2014, p. 16-22

[399] AER draft decision - Attachment 16: Alternative Control Services, November 2014, p. 16-23

rate `may have unintended consequences for the broader Cost Allocation Methodology. The appropriate method of addressing the overhead allocation should be tested with the AER staff responsible for developing and enforcing the Cost Allocation Methodology. On this basis, this recommendation should be considered preliminary until confirmed with the relevant AER staff."[400]

We consider the AER have applied the overhead cap provided by Marsden Jacob without considering the recommendation in full. As Marsden Jacob correctly identify, capping an overhead rate does have consequences for the CAM and the total recovery of efficient operational costs as well as capitalised non-system expenditure. The overhead percentage allocated to a service is an output of applying the approved CAM and should not be utilised as an input. To cap the overhead and not provide for their recovery elsewhere is to effectively "strand" overheads and not permit the recovery of efficient costs. The AER should demonstrate how this approach is consistent with the CAM.

The AER's draft determination simply adopts the cap and recommended labour rates proposed by Marsden Jacobs Associates report. If the AER considers our overheads are inefficient then this should be articulated by reference to the specific components of the overheads.

Times taken to perform the service

As mentioned previously the AER's main concerns with the methodologies employed by Ausgrid to determine the ANS fees were the cost inputs to the methodologies. The time taken to perform each of the tasks was found to fall within benchmark times with the exception of a few services listed below.

"The times taken to perform the service is another key input into deriving fees for ancillary network services. Marsden Jacob determined an implied time taken to perform each Ausgrid's services. The implied times to perform nine of the most frequently requested ancillary network services, as listed below, were also reviewed by Marsden Jacob. Ausgrid's times taken to perform the services were found to fall within benchmark times for these services, except for meter test, disconnection at the meter box, disconnection technical and disconnection at pole top / pillar box."[401]

We do not accept the observation regarding the four outstanding services and note that both the time taken and labour cost and type were provided to the AER to enable a more detailed assessment. Specifically, we provided in Attachment 8.22 of our initial proposal our fee models and methodology for each ANS service, which provided a significant level of detail on each fee and its various components. We consider both our time and labour rate inputs represent realistic and efficient costs of providing these services.

Unreasonable outcomes from benchmarking

Ausgrid note the AER have a range of assessment techniques available in making a determination. This is particularly the case for alternative control services where the AER are not bound by the 'building block' approach.

In developing alternate prices the AER have relied almost exclusively on a selection of advice provided by Marsden Jacobs that were favourable to the AER's conclusion, but also at the same time have ignored the qualifications made by Marsden Jacobs relating to these advice.

Given the limitations of benchmarking, or any single approach, unreasonable outcomes are produced without validating the results. We consider there are instances of this throughout the AER's draft decision that demonstrate this:

- Under recovery on the costs incurred by Ausgrid to support these services. Ausgrid has completed a review of the proposed rates and their forecasted volumes for each of the services to highlight the percentage of under recovery across Ancillary Network Services. From the proposed fees and rates provided by the AER it has been estimated that Ausgrid will be under recovering by 12%, which indicates that cross-subsidisation may still remain with Standard Control Services.
- No review of the flow on effects to other services and parts of the business as outlined by Marsden Jacobs.

We consider it would be prudent to also utilise a number of techniques in forming a view and not to rely heavily on a single measure or benchmark (i.e. Marsden Jacob report). This is of particular importance when there are substantive differences between the amount Ausgrid and the AER consider to be efficient.

There are several instances throughout the AER's draft determination to demonstrate this, specifically:

- Ancillary Network Service 2b (Meter Test Fee)
- Ancillary Network Service 3a (Off Peak Conversion)
- Ancillary Network Service 4b (Disconnection/Reconnection – Disconnection Completed)

[400] Marsden Jacob Associates - Provision of advice in relation to alternative control services - 20 October 2014_1, p. 5

[401] AER draft decision – Attachment 16: Alternative Control Services, November 2014, p. 16-24

- Ancillary Network Service 4d (Disconnection/Reconnection – Pillar/Pole Disconnection)
- Ancillary Network service 5a (Network Tariff Change request)

Ausgrid's position on the above five services is detailed in Attachment 8.08.

Ausgrid does not accept the proposed AER's draft decision ANS prices on the basis that we consider our prices represent a cost-reflective and efficient service.

It is for these reasons and those outlined above that Ausgrid has not revised the proposed ANS prices apart from applying updated cost escalators as we consider our prices represent a more cost-reflective and efficient outcome.

Inconsistencies in the AER's draft decision

In addition to the above, the AER has misinterpreted several of our ancillary network services which has led to draft decision prices that do not align with the services stated in our initial proposal. Particularly noteworthy are the following:

Ancillary network service 4b - disconnection/reconnection – disconnection completed: the AER has more than halved the initial price proposed in their draft determination which has created inconsistencies against fundamentally similar services which have been approved by the AER (ancillary network service 11a - vacant property reconnect/disconnect). Furthermore, this draft decision is also illogical when compared to other services: for example, it suggests that less complex and less costly tasks should cost more[402]. If the draft decision is retained in the final determination, this has the potential to cause significant under-recovery of costs associated with the service, which would need to be subsidised by all customers through SCS.

Ancillary network service 01 - design related services: the AER has incorrectly aggregated individual fees within a single service group, and therefore has not provided appropriate draft determination prices. For instance, "Design Certification" is not a single service but made up of multiple certification services thus should not have a fee allocated to it. Design Certification is associated with common project types i.e. "Underground urban residential subdivision (vacant lots)" which has multiple rates/fees associated with it "up to 5 lots" $357.56, "6-10 lots" $536.34 (FY2015 -16) etc.

Ancillary network service 02a, b - ASP inspections services: Similar to design related services above, these have also been misinterpreted and fees have not been provided for appropriate service descriptions. The different services depend upon the grade of the accredited service provider (ASP) and the number of lots.

A complete list of inconsistencies and areas of concern can be found in Attachment 8.08.

Control mechanism

Ausgrid accepts the AER's approach to the control mechanism to apply a cap on prices for fee-based services, but we also contend that X-factors should apply to the rates for quoted services.

Ausgrid seeks to clarify that individual caps should apply to individual fees as opposed to a single cap applying to all fees. A single cap accounts only for labour cost escalation (as given in Table 166-3 of the AER Draft Determination). Whilst we acknowledge that the majority of services are driven wholly by labour cost, there are services that depend on other cost escalators such as materials and contracted services, hence the need for the individual caps for individual services to ensure correct cost reflectivity. This is important in order to avoid the under-recovery of costs and to prevent cross-subsidisation reoccuring with SCS, where CPI only was applied to prices set by IPART for over 10 years.

Table A-4 (for meter-related ANS) and Table A-5 (for connection-related ANS) in Appendix 1 of Attachment 8.08 show the individual fees and their constituent cost drivers (e.g. labour, materials) and the relevant weightings. The X-factor for each of these individual fees (from which the individual price cap should be derived) will be calculated by relevant weightings to each cost component. For example, the X-factor for 'Network tariff change request (NEW)' will be calculated using 55% of the relevant internal labour escalation index and 45% of the relevant contracted services escalation index as shown in Table A-4. This X-factor will then be used to derive the price cap for this particular service (i.e. the fee).

Furthermore, a cap for each component of the quoted service (i.e. separately for internal labour, materials, contracted services etc.) to FY19 should be provided in the final determination by the AER. This clarification is driven by differences in the calculation of individual fees and charges.

We confirm that the control formulae should include an adjustment factor A which should be set to zero.

[402] Were we to adopt the AER's position, if the $66.90 draft determination fee for service 4b was to be separated into the two components (disconnect and reconnect), this would result in each component being less than the $42.12 (nominal) site visit fee which is illogical.

9. Control mechanism, tariff and pricing arrangements and negotiating framework and critieria

The purpose of this chapter is to respond to the AER's draft decisions on:

1. The implementation of the control mechanism for standard control services (including related recovery matters and customer assignment procedures) set out AER draft decision Attachment 14, see sections 9.1 and 9.4.
2. Ausgrid's Negotiating Framework and Negotiated Distribution Service Criteria set out in AER draft decision Attachment 17; see section 9.2.
3. Ausgrid's transmission pricing methodology set out in AER draft decision Attachment 19, see section 9.3.

The AER has broadly endorsed Ausgrid's proposed approach to the above matters. In the sections below we provide our response to some of the detailed implications of the AER's proposed approach to the control mechanism for standard control services, we have revised our proposed procedures for assigning and reassigning customers to tariff classes in some minor respects to address issues raised in the AER's decision but we have maintained our position on all key areas including the appropriateness of providing notice to retailers of proposed tariffs assignments rather than directly to customer. The AER has accepted Ausgrid's negotiating framework and we have noted the AER draft decision on the negotiated distribution service criteria but have suggested that the language be modified to reflect a principle and criteria approach under the rules rather than mandatory requirements. We have also revised our transmission pricing methodology in light of the AER's rejection of TransGrid's approach to allocating the locational component of prescribed TUOS services. This revision will ensure that Ausgrid's pricing methodology is consistent with whatever final decision the AER reaches with respect to TransGrid's pricing methodology and the treatment of the location component of prescribed TUOS services.

9.1 Application and demonstration of compliance with control mechanism and side constraint mechanism for standard control distribution services

This section provides Ausgrid's response to the AER's draft decision on the control mechanism for Standard Control Services.

Broadly Ausgrid agrees that the approach put forward in the AER's draft determination with respect to the application of the control mechanism is appropriate. However we have some concerns with certain aspects of the proposed formulas to implement the control mechanisms, (which may be unintended transposition errors) and with the way the AER has approached treatment of Ausgrid's transmission revenues. In particular we are concerned that the AER has not appropriately recognised the way in which Ausgrid recovers revenue allowed to be earned in relation to services provided by dual function (transmission) assets and the recovery of designated pricing proposal charges which relate to the recovery of transmission (including Ausgrid's own) costs as well as other costs such as inter-distributor payments.

To assisting understanding and ease of reference Ausgrid has set out each of the elements of the decision and a brief indication of its response in Table 47. Ausgrid's more detailed response is set out in Attachment 9.01.

Table 47 – Overview of Ausgrid's response to the AER's draft determination on control mechanism for SCS

AER Decision	Ausgrid Response	Brief Description of Response
Revenue cap Control mechanism for standard control services is revenue cap.	• Accept as rules require that control mechanism be the same as that specified in the AER's framework and approach paper.	
Application of revenue cap. Revenue cap comprised of annual revenue requirement (ARR) for distribution and maximum allowed revenue (MAR) for transmission services (dual function assets) calculated in accordance with revenue cap formulas in Figures 14-1.	• In principle accept formula, but will seek further consideration of some elements of the formula and the treatment of CPI for transmission revenues as well as seek to clarify the operation of the revenue cap to Ausgrid's transmission revenues.	Ausgrid seeks reconsideration of the AER's rejection of its proposal to apply the same CPI definition to the revenue cap for distribution and transmission. Ausgrid's makes a further submission on the implications for our opex forecasts of not allowing recovery of certain emergency recoverable works through an E factor. Ausgrid seeks further consideration of mechanism for adjustments for incentives and the transitional year revenues for some alternative control services. Ausgrid requests that the determination expressly provides that the "Price" component for year t in the revenue cap formula includes the unders and overs adjustment.
Side constraints Side sonstraints apply to price movements for each tariff class must be consistent with formula in Figure 14-2.	• Ausgrid disagrees with the formula in Figure 14-2 on the grounds that it will unreasonably limit the scope for tariff re-balancing in FY 2015/16. • Ausgrid have proposed an alternative formula that address our concerns and corrects for two unintended errors in the formula in Figure 14-2.	Ausgrid objects to the formula and proposes that the permissible percentage in the formula be expressed as the greater of a CPI-X limitation plus 2% or CPI plus 2%. Ausgrid is seeking to the AER to adopt a consistent CPI treatment. Ausgrid also notes that there are two unintended errors in formula in Figure 14-2: (1) The price change being both less than or equal to and equal to (2) The inclusion of " TUOS" in the side constrain formula is not correct.
Unders and overs accounts Ausgrid must demonstrate compliance with the control mechanism for standard control services in accordance with Appendices A and B.	• Ausgrid disagrees with aspects of Appendix A which addresses the DUOS unders and overs account. • Appendix B addresses "TUOS" unders and overs account but should address "designated pricing proposal charges unders and overs account".	Ausgrid does not accept the AER's draft decision not to apply interest to the opening balance in year "t" The AER's decision conflates designated pricing proposal charges and Ausgrid's recovery of revenue allocated to its transmission or dual function assets services. Ausgrid cannot account separately for its transmission revenue due to the application of the coordinating TNSP provisions of the rules.
Application of tolerance limits	• Ausgrid disagrees with the AER's approach to tolerance limits.	Ausgrid seeks reconsideration of the AER's rejection of our proposed approach to tolerance, particularly with respect to imposing a limit on the recoupment of residual metering asset costs.
"TUOS""Under/ over recovery Ausgrid must submit as part of its annual pricing proposal, a record of the amount of revenue recovered from TUOS charges and associated payments in accordance with Appendix B.	• Same issue as raised in unders and overs account section above, the reference should be to "Designated pricing proposal charges" not TUOS.	
Jurisdictional schemes reporting Ausgrid must report to us its jurisdiction scheme amounts recover in accordance with Appendices C.	• Accepted Ausgrid's proposed approach, except in respect to the inclusion of interest in year t.	Ausgrid does not accept the AER's draft decision not to apply interest to the opening balance in year "t" and seeks reconsideration of this issue.

9.2. Ausgrid's transmission pricing methodology

This section responds to the AER's draft decision set out in Attachment 19 - Pricing methodology.

Ausgrid notes that the AER has accepted all aspects of Ausgrid's pricing methodology as meeting the requirements of the rules except for the treatment of the allocation of the locational component of prescribed TUoS services carried out by TransGrid. The AER has indicated that the draft decision is "not to approve this aspect of TransGrid's proposed methodology, so it follows that we do not accept this part of Ausgrid's too".[403]

Ausgrid has conferred with TransGrid and understands that it is proposing to modify its proposed approach to the allocation of the locational component in response to the AER's decision.

Ausgrid has reviewed its pricing methodology and has modified it so that it is clear that this component is carried out by TransGrid in accordance with its methodology as approved by the AER and that Ausgrid's methodology does not in any way pre-empt how this task carried out by TransGrid.

We have done this by deleting the following paragraphs from section 3.4.3 and replacing them with a more general reference to the task carried out by TransGrid:

> *Allocation of the locational component of prescribed TUOS services is carried out by TransGrid using the CRNP methodology, which assigns a proportion of shared network costs to individual customer connection points. TransGrid does this using the TPRICE cost reflective network pricing software used by most TNSPs in the NEM. Details on this calculation can be found in TransGrid's transmission pricing proposal.*
>
> *The CRNP methodology requires three sets of input data:*
>
> - *An electrical (loadflow) model of the network;*
> - *A cost model of the network (the results of the cost allocation process described in Appendix A); and*
> - *An appropriate set of load/generation patterns.*

Ausgrid's proposed amendment will ensure that its proposed methodology is consistent with the final decision of the AER with respect to TransGrid's pricing methodology. In all respects now, Ausgrid's transmission pricing methodology will implement TransGrid's pricing methodology as approved by the AER in its final decision. This will also ensure that Ausgrid's pricing methodology will be able to continue for the full 2014-19 regulatory control period, notwithstanding that TransGrid may have a new pricing methodology in 2018-19 as it has proposed to the AER that its regulatory control period be for four years including the transitional year, that is 2014-2018.

Ausgrid's revised transmission pricing methodology is provided at Attachment 9.02 in both a confidential and publicly available form. For ease of reference we have also included a version in mark-up which indicates the specific revisions which have been made to address the matters raised in the AER's draft determination.

9.3 Procedures for assigning customers to tariff classes.

This section responds to the AER's decision set in section D of Attachment 14 to the its draft decision "Control mechanism for standard control services".

The AER generally accepted Ausgrid's proposed procedures for assigning customers to tariff classes except for two aspects relating to the notification of retailers of proposed tariff class changes and thresholds for assigning and reassigning customers to the customer reflective network tariff class. Ausgrid does not accept these two proposed changes to its proposed procedures. Whilst Ausgrid has made minor revisions to address the AER's concerns we are concerned that the AER's proposed changes will be unduly restrictive upon its ability to transfer customers to and from the CRNP tariff class and that the requirement to notify customers rather than their retailer is not consistent with the framework established under the National Energy Retail Law. Ausgrid's detailed response to the AER's decision on these procedures and our revised procedures are set out in in Attachment 9.03.

9.4. Ausgrid's negotiating framework and negotiated distribution service criteria

This section responds to the AER's draft decision set out in Attachment 17- Negotiated distribution services framework and criteria.

The AER has accepted Ausgrid's negotiating framework without amendment and consequently Ausgrid makes no further submission or proposal in relation to our proposed framework.

As part of its initial regulatory proposal, Ausgrid proposed the AER adopt the negotiated distribution service principles set out in clause 6.7.1 of the NER. Subsequently in June 2014, the AER issued its proposed approach to Ausgrid's negotiated distribution service criteria, which, whilst based on the principles in clause 6.7.1 adopted a mandatory language rather than a principles or criteria based approach. The AER has not explained the basis of its approach or why it has departed from the language of the principles and criteria in clause 6.7.1. In the absence of any basis for its proposed approach we recommend that the AER move away from mandatory requirements in its criteria revert to the language which is more consistent with clause 6.7.1.

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[403] AER draft decision – Attachment 19, p. 19-10.

Glossary

Abbreviation	Meaning
$2013/14	Real dollars. This denotes the dollar terms as at 30 June 2014.
$nominal	This is the dollar of the day.
2014-19 period	The period that comprises both the transitional regulatory control period 1 July 2014 to 30 June 2015 and the regulatory control period 1 July 2015 to 30 June 2019 (2015-19 regulatory control period).
2015-19 regulatory period	The regulatory control period commencing 1 July 2015 to 30 June 2019.
ACS	Alternative control services
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARR	Annual revenue requirement
Augex	Augmentation expenditure model
CAM	Cost allocation method
Capex	Capital Expenditure
CAPM	Capital asset pricing model
CCF	Climate Change Fund
CCP	Consumer Challenge Panel
CESS	Capital expenditure sharing scheme
CPI	Consumer Price Index
CRNP	Cost reflective network price
Current regulatory period	Regulatory control period of 1 July 2009 to 30 June 2014.
DFA	Dual function assets
DGM	Dividend growth model
DMBSS	Demand management benefit sharing scheme
DMEGCIS	Demand management embedded generation connection incentive scheme
DMIA	Demand management innovation allowance
DMIS	Demand management incentive scheme
DNSP	Distribution network service provider
Draft decision / determination	AER draft decision, Ausgrid distribution determination 2015/16 – 2018/19, Nov 2014
DRP	Debt risk premium
DUOS	Distribution use of system
EBSS	Efficiency benefit sharing scheme
ECC	Ethnic Community Council of NSW
EI	Economic Insights
ERW	Emergency recoverable works

Abbreviation	Meaning
EWON	Energy & Water Ombudsman NSW
EY	Ernst & Young
F&A	Framework and approach
FEMCA	Failure modes effects criticality analysis
FFM	Fama-French 3 Factor Model
GFC	Global financial crisis
IBT	Inclining block tariff
Initial proposal / initial regulatory proposal / regulatory proposal	Ausgrid's proposal for the regulatory control period 1 July 2015 to 30 June 2019 (including 2014/15 information)
Last regulatory period	Regulatory control period of 1 July 2004 to 30 June 2009
LIDAR	Light detection and ranging
LNSP	Local network service provider
MRIM	Manually read interval meter
MRP	Market risk premium
NCOSS	NSW Council of Social Services
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NER or rules	National Electricity Rules
Next five years	The 5 year period between 1 July 2014 to 30 June 2019
Next regulatory period	Regulatory control period of 1 July 2015 to 30 June 2019
NMI	National Meter Identifier
NUOS	Network use of system
Opex	Operating expenditure
PIAC	Public Interest Advocacy Centre
PTRM	Post tax revenue model
RAB	Regulatory asset base
Repex	Replacement expenditure model
Revised proposal	Ausgrid's revised regulatory proposal and preliminary submission for period of 1 July 2015 to 30 June 2019 (including 2014/15 information and supporting attachment) dated 20 January 2015
RIN	Regulatory information notice
RoR	Rate of return
SCER	Standing Council on Energy and Resources
SCS	Standard control services
STPIS	Service target performance incentive scheme

Abbreviation	Meaning
TEC	Total Environment Centre
the transitional rules	The National Electricity Rules applicable to the transitional regulatory proposal
TOU	Time of use
Transitional period / transitional year	Regulatory control period of 1 July 2014 to 30 June 2015
Transitional regulatory proposal / transitional proposal	Ausgrid's proposal for the transitional period submitted under clause 6.8.2 of the transitional rules
TUoS	Transmission use of system
VCR	Value of customer reliability
WACC	Weighted average cost of capital
X factor	(%) change in real revenues between regulatory years

Attachments

Attachments	
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1.02	Statement of Chief Operating Officer of Ausgrid (CONFIDENTIAL)
1.03	Commissioner - Fire and Rescue NSW: Letter to CEO of NNSW
1.04	Commissioner - NSW Rural Fire Service: Letter to CEO of NNSW
1.05	Frontier Economics - Review of AER's econometric models and their application in the draft determination for Networks NSW
1.06	Huegin - response to draft determination on behalf of NNSW and ActewAGL - Technical response to the application of benchmarking by the AER
1.07	David Newbery, Cambridge Economic Policy Associates: Expert report, Jan 2015
1.08	Pacific Economics Group (PEG) - Statistical Benchmarking for NSW Distributors, Jan 2015
1.09	Advisian - Review of AER benchmarking, January 2015
1.10	PWC - Independent Expert Advice on appropriateness of RIN data for benchmarking comparisons, Jan 2015
1.11	Standard and Poor's: Credit assessment and ratings (CONFIDENTIAL)
1.12	UBS: response to the Networks NSW request for financeability analysis following the AER Draft Decision of November 2014 (CONFIDENTIAL)
1.13	R2A: Asset/System Failure Safety Risk Assessment
1.14	AON: Insurance Advice Report - Insurance costs and coverage impacts arising from cuts in vegetation management expenditure for the 2014-2019 regulatory period (CONFIDENTIAL)
1.15	Environmental implications
1.16	Jacobs - System Capex and Maintenance Prudency Assessment
1.17	Ausgrid response to Jacobs prudency assessment (provided at Attachment 1.16)
1.18	Letter from CEO of Roads & Maritime Services
2.01	Customer Social Media Engagement Strategy
2.02	Your Power, Your Say Facebook activity report
2.03	Ausgrid Facebook analysis of blackout activity
2.04	Retailer Forum Engagement Report
2.05	Letter to stakeholders from Ausgrid COO
2.06	Ausgrid online media monitoring report
2.07	Ausgrid Community Engagement System Overview
2.08	Ausgrid Regional briefings presentations
2.09	Stakeholder Briefings – our plans and priorities summary report
2.10	Customer Council Improvement Project scoping paper
2.11	IPSOS Research - Willingness to pay for network services

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2.12	Letter from Woolcott Research on Ausgrid research
2.13	Email from Western Power Distribution: Stakeholder Engagement Manager
2.14	Dec 19 Media Release NSW Government Energy Minister
2.15	Consumer Infographics
3.01	Revised proposal on classification of services
3.02	Application of STPIS - derivation of key parameters
4.01	Revised RAB - Distribution
4.02	Revised RAB - Transmission
4.03	Revised adjustment of RAB for distribution standard control and metering alternative control services
4.04	Advisian - Review of standard and remaining lives of assets
4.05	Calculation of D-factor and DMIA adjustment for 2009-14
4.06	Ernst & Young - Advice on movement in provisions
4.07	Calculation of EBSS carryover for 2009-14
4.08	Revised PTRM - Distribution
4.09	Revised PTRM - Transmission
4.10	Energy volume forecast
4.11	Revised connection policy
5.01	Demand forecasting - revised methodology
5.02	2014 Spatial demand forecasts
5.03	Area plan projects - 2014 review of preferred strategies
5.04	HV distribution capacity model
5.05	Strategic delivery and workforce plans for 2015-19 (CONFIDENTIAL)
5.06	'Weighted asset value at risk' analysis
5.07	Assessment of EMCa technical review
5.08	Jacobs – Review of AER draft decision - REPEX
5.09	2014 Replacement plan review
5.10	Application of REPEX to modelled categories - revised proposal
5.11	Quantitative risk evaluation - selected replacement projects
5.12	Advisian - Networks NSW independent review of the risk based prioritisation process for Networks NSW - post implementation review
5.13	2014 Reliability investment plan review (inc STPIS offset)
5.14	Demand management opex and capex overview
5.15	Cost escalation updates (CONFIDENTIAL)
5.16	Updated customer numbers

Attachments	
5.17	Statement prepared by Group Executive Network Strategy
6.01	ARUP – Ausgrid labour analysis report (CONFIDENTIAL)
6.02	CEG – Labour unit cost – review of Deloitte report (CONFIDENTIAL)
6.03	K&L Gates: Comparison and Analysis of Enterprise Bargaining Agreement for Distribution Networks (CONFIDENTIAL)
6.04	Transformation in the Electricity Distribution Network Industry
6.05	Revised opex model -SCS
7.01	CEG - Efficient debt financing costs
7.02	Frontier Economics - Cost of debt transition for the NSW DNSPs
7.03	CEG - Estimating the cost of equity
7.04	SFG - Report on the cost of equity for ActewAGL and the NSW DNSPs
7.05	Bruce Grundy - Letter from Bruce Grundy to Justin De Lorenzo - 9 January 2015
7.06	NERA - Memo on Revised MRP estimates to 2013
7.07	Ausgrid's revised proposal on gamma
7.08	AOFM - Letter from Michael Bath to Steve Knight re: domestic interest rate swaps
7.09	Statement of Justin DeLorenzo, Chief Financial Officer, Networks NSW (CONFIDENTIAL)
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8.04	Revisions to the type 5 and type 6 metering proposal
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8.08	Revisions to the ancillary network services proposal
8.09	Ancillary network services models - metering
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9.01	Application and Demonstration of compliance with control mechanism for standard control services
9.02	Ausgrid's proposed transmission pricing methodology
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