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George Maltabarow
Managing Director

570 George Street
Sydney NSW 2000
All mail to GPO Box 4009
Sydney NSW 2001
T +61 2 9269 2112
F +61 2 9264 2982
www.ausgrid.com.au

Mr J Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear ~~Mr Pierce~~ John

Ausgrid appreciates the opportunity to provide a submission in response to the Australian Energy Market Commission's (AEMC) directions paper on the rule changes proposed by the Australian Energy Regulator (AER) and the Energy Users' Rule Change Committee (EUC).

Ausgrid has provided significant input to the Energy Networks' Association's (ENA) submission on the AEMC's directions paper. Our submission builds on the thorough analysis undertaken by representatives in the ENA submission as well as the attached expert reports.

Our submission outlines specific factors affecting Ausgrid as part of the current rule change process. In particular, the current rule change process coincides with the development of Ausgrid's regulatory proposal for the 2014–19 distribution determination. This is a significant concern for Ausgrid because it has already begun developing its regulatory proposal in accordance with the current electricity rules. The AEMC's directions paper contemplates major changes to the current rules framework, which may require Ausgrid to revise and potentially re-start its planning and development for the 2014–19 distribution determination.

In response to a specific question in the AEMC's directions paper, we have conducted substantial analysis of the factors that have driven price increases for its network over the current regulatory period. This analysis is in addition to analysis conducted by the ENA and shows that the current rules framework has not driven excessive network price increases over the current regulatory period. We have provided the details of this analysis in an attachment to our submission.

Ausgrid is also keenly aware of the influence of current market conditions on the rate of return and, in particular, the effect of current market conditions on short term estimates of the risk free rate and the cost of debt. We reiterate our arguments from our December submission regarding governance and decision making arrangements on the rate of return. In addition, Ausgrid has worked with its principal debt provider T-Corp to develop its submission on the rate of return frameworks and the cost of debt.

Our submission outlines that the current rate of return framework for electricity distribution can be flexible enough to deal with some of the issues raised by stakeholders. We suggest these options are exhausted before concluding change is required to the current electricity distribution rules for setting the rate of return. To the extent that revisions are required, we agree that this issue is significant enough to warrant separate in-depth review outside this rule change timetable.

Ausgrid is keen to provide further information to the AEMC on its submission if required. If you have any enquiries in relation to Ausgrid's submission please feel free to contact Brendon Crown on (02) 9269 3493 or at bcrown@ausgrid.com.au.

Yours sincerely

George Maltabarow

GEORGE MALTABAROW
Managing Director

Directions paper on AER/EUC rule change proposals
Ausgrid Submission

16 April 2012

Ausgrid submission on AEMC directions paper
16 April 2012

Contents

1 INTRODUCTION 1
2 IMPACT OF THIS RULE CHANGE ON AUSGRID'S REGULATORY DETERMINATON PROCESS 2
3 CAPITAL EXPENDITURE AND OPERATING EXPENDITURE ALLOWANCES 4
4 CAPITAL EXPENDITURE INCENTIVES 7
5 RATE OF RETURN FRAMEWORKS 8
6 COST OF DEBT 12

1 Introduction

Ausgrid welcomes the opportunity to comment on the AEMC's directions paper for the proposed rule changes submitted by the Australian Energy Regulator (AER) and the Energy Users' Rule Change Committee (EUC). In Ausgrid's view, significant changes to the current electricity revenue rules for distribution network service providers are not necessary to address issues that have been raised by AER and EUC's rule change proposals. However, should the AEMC believe changes are necessary, the AEMC must take into account the fact that Ausgrid has already commenced the regulatory determination process with the AER. Therefore, Ausgrid also considers that any change to the current rules so close to Ausgrid's 2014–19 distribution determination process would place it at a significant disadvantage in preparing and submitting its regulatory proposal, due in May 2013.

As an active member of the Energy Networks' Association (ENA), Ausgrid has contributed to the comprehensive ENA submission in response to the directions paper. We fully support the industry submission and would recommend the submission and expert reports to the Commission. Our submission is intended to build on the ENA submission and, in a few key areas, we have provided additional context from Ausgrid's perspective in respect of the AEMC's questions. In particular, we have focussed on the following issues:

- Impact of the rule change on Ausgrid's 2014–19 regulatory determination process.
- The factors that have been driving network price increases – Ausgrid has conducted significant analysis on the factors that have been driving price increases for its network. This analysis demonstrates that the expenditure setting rules under the NER have not been driving excessive price increases and that factors including artificially depressed revenues/prices under previous frameworks, changed license conditions, volume demand decreases and the global financial crisis are the major factors that have driven recent price increases. A detailed attachment sets out Ausgrid's analysis of these factors.
- The rate of return frameworks under the NER – In Ausgrid's view, the current electricity distribution rate of return framework is the preferred model for determining the rate of return electricity distribution NSPs and, on that basis, should be applied to the transmission framework as well, if a single framework is desirable.
- The cost of debt – The trailing average approach to estimating the cost of debt suggested by the EUC would require much greater consultation than is possible as part of the current rule change timetable. Ausgrid would prefer a framework which gave flexibility in setting both the cost of debt and the risk free rate estimate under current market conditions use a long term averaging period (historically observed over 10 years). However, we consider that this is possible under the current electricity distribution rules so, assuming our interpretation is correct, no rule changes are required to implement this approach.

2 Impact of this Rule change on Ausgrid's regulatory determinaton process

We noted in our response to the AEMC's consultation paper that, given the broad range of issues still under consideration by the AEMC, the rule change process creates significant risks and uncertainty for Ausgrid in its preparations for the 2014–19 regulatory determination.

The AEMC has noted that it will consider transitional issues as part of any potential rule changes at the time of its draft rule determination on 26 July 2012. This gives Ausgrid very little certainty as to what changes, if any, will apply to us when preparing the 2014-19 regulatory proposal. In particular, the AEMC has indicated that it will consider changes to the rules regarding the assessment of capital and operating expenditure, capital expenditure incentives, and the rate of return. Because these are key inputs to determining Ausgrid's regulated revenues/prices, we have already begun developing its regulatory proposal in these areas based on the existing National Electricity Rules (NER). Anything other than minor changes to the rules is likely to require Ausgrid to significantly alter its current approach to forecasting costs and developing its regulatory proposal, which would place it at a material disadvantage compared to a situation where the rules remained largely unchanged.

We note as part of the AEMC's Economic Regulation of Transmission revenues review and Rule change process, the Commission was very keen to ensure that businesses were not jeapordised by the co-incidence of the Rule change process with current determination cycles. The Commission noted with respect of Powerlink that "the concurrent revenue reset process and the review of the transmission revenue rules has presented significant challenges for all parties"[1] and "substantial investment in long term assets should not face unnecessary regulatory risk from lack of clarity or certainty about the transition to the new regime."[2]

We note and support the Commission's general policy approach in respect of the last rule change that an NSP should neither be in a better or worse position than other NSPs as a result of the concurrence of its reset process with this review of the revenue rules[3].

Capital and operating expenditure allowances

Ausgrid has already begun the process of forecasting capital and operating expenditure based on the current assessment framework. A change to the current framework would require Ausgrid to consider the implications of a new assessment framework for capital and operating expenditure and then review, revise and, if necessary, restart its planning process to match with new rule requirements.

For example, the AEMC is contemplating changes to the expenditure objectives and determinative factors that the AER must take into account when assessing a DNSPs proposal. This would change the assessment framework for forecast expenditure, and would place Ausgrid at a significant disadvantage compared to if it had certainty as to the framework that applied before it began its forecasting approach. Obviously the extent of the disadvantage is dependent on the extent of the change and the proximity of the change to the proposal date. Nevertheless, we would advocate strongly that the AEMC take these considerations into account to the extent that it intends to make any change to the existing decision making framework around capital and operating expenditure allowances.

Capital expenditure incentives

The AER has proposed that only 60% of any capital expenditure in excess of a regulatory allowance be included in the regulatory asset base (even if the additional assets are used to provide standard control services). Ausgrid would be placed at a significant disadvantage if the rules were changed to apply any ex-post assessment of capital expenditure (over the 2009-14 regulatory period) either in the form suggested by the AER or any other form. Any rule change implementing an ex-post assessment of capital expenditure would expose Ausgrid to an incentive mechanism that it had no information about when the actual capital expenditure was planned for and incurred. For this reason, Ausgrid should not be subject to any changes to the incentive framework for past capital expenditure in its upcoming 2014–19 distribution determination.

We would also argue that such an incentive regime imposed on the 2014-19 regulatory control period, if known in advance, would otherwise be taken into consideration in developing our forecasting approach and methodology.

We are not afforded this opportunity if Rules are modified in late 2012. This again places Ausgrid at a disadvantage in developing regulatory proposal forecasts in May 2013 consistent with any amended Rules.

[1] AEMC, *Final Determination – Economic Regulation of Transmission Services*, November 2006, p126
[2] AEMC, *Final Determination – Economic Regulation of Transmission Services*, November 2006, p123.
[3] AEMC, *Final Determination – Economic Regulation of Transmission Services*, November 2006, p127

The AEMC has also flagged the possibility of allowing the AER to implement pilot or test incentive schemes within a controlled environment. In Ausgrid's view, the current rules do not unduly limit the AER's ability to apply incentive schemes. The current rules require the AER set out its likely approach to the application of incentive schemes to Ausgrid's 2014–19 determination through its framework and approach consultation process.[4]

The rules appropriately require the AER publish its framework and approach paper within a sufficient timeframe for it to be of use in the development of Ausgrid's regulatory proposal.[5] The AER has already begun its framework and approach consultation process and must finalise this process in November 2012. The AEMC's draft rule determination is not due to be published until 26 July 2012 and a final determination is not scheduled to be published until October 2012. Given these timeframes, any new incentive schemes arising from the current rule change process should not be applied to Ausgrid because it would not provide sufficient time for it to consider the implications of such schemes for the framework and approach process which has already commenced and on Ausgrid's planned capital expenditure over the 2014–19 period.

Rate of return frameworks and the cost of debt

The AER has proposed that the rate of return rules across the NER and the NGR should align more closely to the current electricity transmission rate of return framework. Ausgrid agrees with the AEMC's position that the electricity transmission rate of framework does not provide sufficient flexibility to adapt to changing circumstances (such as the GFC) and that the electricity distribution or gas rate of return frameworks are preferable.

The AEMC's directions paper canvasses a range of issues that may result in changes to the current rate of return frameworks. However, given the importance of the rate of return in determining regulated revenues and the close proximity of the rule change process to Ausgrid's 2014–19 regulatory determination, any new rate of return rules should not be applied to Ausgrid for the 2014–19 determination. A number of electricity distribution determinations have been completed under the existing electricity distribution rate of return framework, which means there is some clarity over how the current framework operates. A new rate of return framework would expose Ausgrid to significant (and unwarranted) uncertainty about how the rate of return would be set for the 2014–19 period.

[4] NER, cl. 6.8.1(b)
[5] NER, cl. 6.8.1(e) & (f)

3 Capital Expenditure and Operating Expenditure Allowances

Question 2 The Commission seeks further evidence on the drivers for increases in network costs, and in particular on the link between capex and opex allowances under the NER and such increases in network costs.

The AEMC's direction paper sought further evidence on the drivers for increases in network costs. We refer the AEMC to the ENA's submission and attached NERA report which summarises the drivers of network price increases across jurisdictions. We have contributed to the NERA analysis and support its findings.

Drivers of network price increases

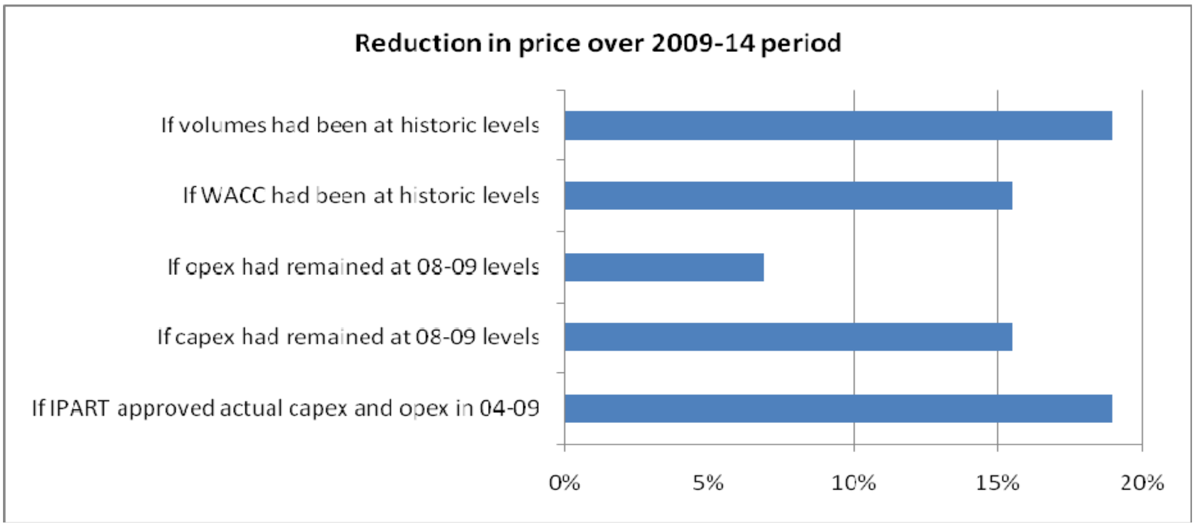
Attachment A of our submission supplements the ENA submission by providing a detailed quantification of the drivers of Ausgrid's network prices in the 2009-14 period. We build on the general methodology used in the ENA submission, but seek to highlight unique circumstances underlying Ausgrid's price increase.

Our analysis identifies a co-incidence of drivers that led to a significant price movement for our customers in the 2009-14 period. We show that increased investment to replace ageing assets and meet new licence conditions were a catalyst for increased network prices.

More importantly however, we show that the price rise was magnified by unsustainably low levels of investment under previous frameworks. We also highlight how declining volumes and higher cost of capital compounded the price impact. Our findings on key drivers are summarised below and explained in greater detail in Section 2 of Attachment A.

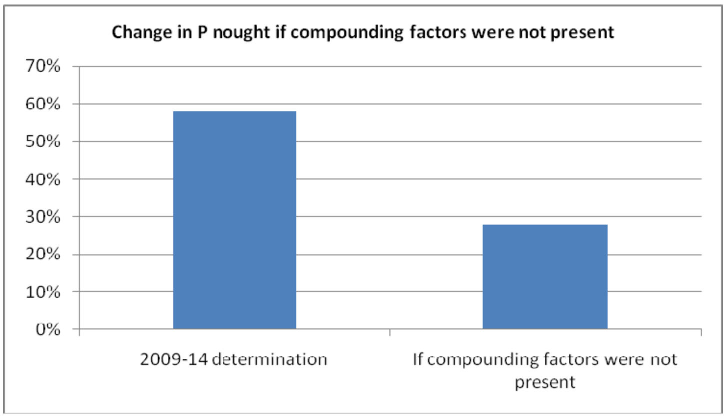
Drivers	Impact
Unsustainably low investment in previous periods	The RAB value was significantly lower than the modern day value, which meant that customers were paying relatively low prices in previous periods. If replacement had started earlier, customers would have faced a lower price impact in the 2009-14 period.
Customers did not pay cost reflective prices in 2004-09 period	Ausgrid's out-turn capital and operating costs in 2008-09 were well above what IPART allowed at the beginning of the period. This was also magnified by Ausgrid's decision to invest more heavily in capacity and replacement expenditure, which was not reflected in the prices being paid by customers in the 2004-09 period. When prices were re-calibrated in the 2009-14 determination, customers faced a step change in prices to reflect the true costs of providing these services.
Increased costs in 2009-14 compared to 2004-09	Ausgrid's out-turn capital and operating expenditure increased sharply in the latter half of the 2004-09 regulatory control period. Capital and operating expenditure increased further from 2008-09 levels. At the same time, the cost of capital in the market increased from its historical trend as a result of the GFC. While capex and opex increases explain some of the price movement, other factors such as the high cost of capital were key contributors to the magnitude of the price movement
Volume growth was significantly lower than historical trends	If volume growth had been at historical levels, the price impact faced customers would have been far less.

Ausgrid quantified the impacts of each of these drivers using a similar methodology to the ENA. Our results show that the price impact faced by customers in the 2009-14 period would have been far less under each scenario. We also show that WACC and volumes were not in line with historic levels, and that this compounded the price impact. This can be seen in the diagram below.



Ausgrid also developed a scenario to analyse the price impact if compounding factors were not present. In undertaking this scenario we increased volumes to historic levels, reduced WACC to historic levels, and assumed that IPART had approved our actual opex and capex in 2004-09. We kept capital expenditure and operating expenditure at the same levels as determined by the AER in the 2009-14 determination.

The results are illuminating in showing that the same level of capex and opex would have resulted in a P nought[6] impact of 28 per cent rather than 58 per cent (a reduction in price impact of 52%). Our analysis also shows that the X-factors would have been significantly lower for our customers, as seen below.



	2009-10	2010-11	2011-12	2012-13	2013-14
2009-14 determination	-17.86	-18.18	-18.18	-18.18	0.77
Amended X-factors	-9.01%	-9.00%	-9.00%	-9.00%	-5.00%

Question 3 Would it be appropriate for the wording of the NER to be clarified to better reflect the policy intent?

Ausgrid supports the ENA position. It is important to clarify the intention of the MCE when establishing rules regarding the economic regulation of distribution networks. When undertaking this exercise, the MCE was clear in ensuring that rules regarding distribution revenue regulation only differed to the extent there was a justifiable difference between the nature of transmission and distribution networks. However, in establishing the rules framework for distribution, the MCE was also mindful of its intent to establish "fit-for-purpose" decision making frameworks. The introduction of Clause 6.12 *Requirements relating to draft and final distribution determinations* establishes a framework in which requires the AER to make a series of "constituent decisions" when making a distribution determination. Clause 6.12 also establishes a framework which guides the AER in the reasons it must provide when making their decisions and the discretion afforded to it when making each of those decisions.

[6] P nought is a way of calculating price impact by bringing forward the totality of the price impact to the first year.

It is important to note therefore that the operation of 6.12 deals with far more than operating and capital expenditure forecasts, but 20 different decisions the AER must make as part of a distribution determination. We addressed this in issue detail in our initial submission to the AEMC.[7]

We would therefore recommend to the AEMC that some a careful legal review of the architecture of these Rules be undertaken before reaching conclusions that parts of this architecture are entirely superfluous and on that basis can be easily removed without impacting upon the decision-making framework for distribution.

[7] See Ausgrid, *Submission to the AEMC on AER and Energy Users' rule change proposals*, December 2011, p. 17.

4 Capital Expenditure Incentives

Question 7: In what circumstances would an NSP need to spend more than its allowance under the NER?

Ausgrid supports the ENA position. We would highlight that over expenditure to date is not attributable to the current Rules frameworks. The incentives in relation to over expenditure were set in previous determinations under different regulatory frameworks. Therefore it is misconceived to assert that incentives in the current Rules framework were to blame for over expenditure.

We note in particular that the ENA correctly highlights that over expenditure will occur when the allowance provided by a regulator is insufficient to enable a DNSP to fulfil its obligations to provide a safe and reliable network in the long term. In these circumstances a DNSP will spend more than the allowance despite the financial penalty imposed under the incentive regime.

Ausgrid notes that these circumstances occurred in our 2004-09 period where we overspent our allowance to ensure a safe and reliable long term electricity supply to our customers. Attachment A of our submission shows that the price impact faced by customers would have been far less in the 2009-14 period (but higher in earlier years) had regulators allowed for necessary expenditure. In particular we show that replacement allowances had been suppressed at unsustainably low levels in the late 1990s to 2000s. As a consequence, Ausgrid was compelled to ramp up expenditure in the latter half of the 2004-09 period to address condition and overload issues on the network. More detail is provided in Section 3 of Attachment A.

Question 11: More extensive use of the uncertainty regime means regulatory arrangements more closely resemble commercial contracts. Is this appropriate?

As we noted in our December submission, the contingent project regime, if applied in distribution would result in either too few projects to be meaningful or too many projects to be practically feasible.

A contingent project framework may be suitable where there is a clearly defined event triggering significant investment (for example, a new generator). In these cases, the TNSP cannot use a portfolio approach to determine an appropriate allowance to account for the uncertainty. It is likely that there would only be a few of these types of projects, and therefore be administratively practical for the AER to consider on an ad-hoc basis during the regulatory period.

Distribution networks are characterised by a large number of smaller scale projects. In most cases, the trigger for investment can be forecast with certainty (for example, replacement needs or organic growth). In a minority of cases, investment requirements are based on uncertain events, for example a large customer connection or large land release. However in these cases, distributors are also able to account for uncertainty by taking a more probabilistic approach to uncertain events, such that there is unlikely to be a windfall gain or loss. Ausgrid therefore currently has a probabilistic approach to dealing with uncertain projects that takes a portfolio view to determine a likely expenditure profile for large uncertain connections to the network.

As distribution projects are generally much smaller than transmission projects, project lead times are significantly shorter. This presents a fundamental issue as contingent projects must be identified in a regulatory proposal. This is often not possible as a DNSP may not become aware of the need for a project at the time of the regulatory proposal. This is not such a concern for transmission projects which may have longer lead times.

The shorter lead times and inability of DNSPs to nominate projects as contingent at the time of the Regulatory proposal also means that the introduction of a contingent project regime for distribution cannot substitute for the present inclusion of overspend in the RAB.

The difference between transmission and distribution was recognised by the MCE when it developed the Chapter 6 Rules the MCE noted that the contingent project regime should not apply to distributors. The MCE stated "Transmission capex can be lumpy and strongly influenced by individual projects, which may suffer a range of external impacts on timing and scope. Distribution capex is more predictable through demand trends. Uncertain distribution projects may be accommodated by pass-through."[8]

In addition to our reservations with the contingent project regime, Ausgrid notes that the proposed Rule sets the materiality threshold at $10 million, unless the AER amends the threshold through optional guidelines. As noted in our earlier comments, the AER would not be able to undertake a revision to the guidelines prior to our regulatory proposal. A threshold of $10 million would mean that a large number of contingent projects may be included in the AER's determination. In effect, this would result in the AER undertaking a series of mini determinations throughout the period, and this would be overly resource intensive.

[8] MCE, *Electricity amendments and further amendments to the electricity and gas rule-change process*, January 2007,Table 2, p. 6.

5 Rate of return frameworks

Question 20 Are some WACC parameter values more stable than others, and sufficiently stable to be fixed with a high degree of confidence for a number of years into the future? Would it be practical for periodic WACC reviews to cover only some parameters that are considered relatively stable in value, and require others to be determined at the time of each regulatory determination?

The rate of return needs to be considered as a whole at the time of a regulatory determination to ensure that regulated businesses are given a sufficient opportunity to recover their efficient costs of finance. All of the parameters within the rate of return are inter-related, and as such, they need to be considered together to ensure a reasonable rate of return. The rate of return is estimated as a weighted average cost of capital, which is described by the following equation:

WACC = E/V × Cost of equity + D/V × Cost of debt

The best estimate of the rate of return would maintain consistency across each of the parameters within the cost of equity and the cost of debt because they are combined to form the overall rate of return. In some cases parameters are explicitly inter-related. For example the capital asset pricing model (CAPM), which is used to estimate the cost of equity, incorporates a risk free rate parameter and a market risk premium parameter:

Cost of equity = Risk free rate + Equity beta × Market risk premium

Within the CAPM, the market risk premium needs to be estimated consistently with the risk free rate proxy because of the following relationship:

Market risk premium = Expected return on the market portfolio – Risk free rate

Similarly, the cost of debt needs to be estimated consistently with the risk free rate because:

Cost of debt = Risk free rate + Debt risk premium

The examples above demonstrate some of the linkages between rate of return parameters. However, data constraints can limit the ability to estimate WACC parameters consistently. This has been demonstrated by the difficulty of estimating a forward looking cost of debt using a benchmark 10 year term to maturity (consistent with the 10-year term to maturity assumed for the risk free rate proxy).[9] Nevertheless the requirement to maintain consistency across parameters remains an essential factor when determining the best estimate of the WACC. For this reason Ausgrid does not consider that certain rate of return parameters can (or should) be fixed for a number of years because they are likely to be stable for a number of years, whereas others can be determined at the time of a regulatory determination. Ausgrid considers that a best estimate of the rate of return would need to consider the best available evidence on individual parameters as well as the overall rate of return at the time of a determination.

Question 21 Would it be useful if the AER periodically published guidelines on its proposed methodologies on certain WACC parameters as opposed undertaking periodic WACC reviews that locks in parameter values for future revenue/pricing determinations?

In our December submission we recommended that the AEMC look at developing a framework that would allow an expert panel to engage in significant and important detail regarding issues of both cost of debt and cost of equity. This would be consistent with the AEMC's view that the Rule enforcer should be guided in its discretion of interpretation of the Rules and would potentially overcome the observations noted in the CEG report that the AER seeks to use the Rules to adopt the lowest possible rate of return outcome.

Absent of changes to the governance of decision-making around rate of return, current rate of return framework for electricity distribution businesses provides the best process for setting the WACC, compared to the other methods currently in place. The periodic WACC review provides guidance on the likely approach for setting the WACC and where issues are not contentious they do not need to be re-considered at the time of a determination. However, where there is a material change in circumstances (eg. market deterioration or market improvement) this can be considered when

[9] There has been significant debate about the appropriate cost of debt forecast for a 10 year horizon given the limited availability of data on Australian 10 year BBB+ corporate bond yields in recent years. See for example Australian Competition Tribunal, *Application by APT Allgas Energy Limited (No 2) [2012] ACompT 5*, 11 January 2012; Australian Competition Tribunal, *Application by Envestra Limited (No 2) [2012] ACompT 4*, 11 January 2012; Australian Competition Tribunal, *Application by United Energy Distribution Pty Limited [2012] ACompT 1,* 6 January 2012; Australian Competition Tribunal, *Application by Jemena Gas Networks (NSW) Ltd (No 5) [2011] ACompT 10,* 9 June 2011.

setting the rate of return at the time of a determination. Moreover, this rate of return framework allows the overall rate of return to be fully considered at the time of a determination.

Ausgrid agrees with the AEMC that a framework such as the electricity transmission rate of return framework is too inflexible to adapt to changing circumstances[10] because it locks in parameter values for a five year period. The current rate of return process for electricity distribution provides a better framework, where investors and regulated businesses are provided with strong guidance on the AER's approach to rate of return parameters but there is also flexibility to respond to changing market conditions.

Question 22 Given the uncertainty in estimating certain parameters, should the AER be required to produce the best possible values for all parameters or adopt a range from which it can choose a preferred estimate? Which WACC parameters are inter-related and should the rules recognise the inter-relationships of these WACC parameters?

Ausgrid considers that each rate of return parameter should be estimated as a point estimate rather than set as a range of possible values. Ausgrid agrees with the AEMC that there is uncertainty when estimating rate of return parameters. However, setting point estimates for each parameter provides greater certainty to investors and regulated businesses than setting ranges. Moreover, each rate of return parameter can be estimated with a higher degree of confidence than is possible for the overall rate of return.

Financial models such as the capital asset pricing model (CAPM), and others, allow us to estimate the cost of equity and the overall rate of return with a greater degree of confidence than if we were to estimate the overall rate of return by reference to observable rates of return. This is because each parameter within the rate of return can be benchmarked and observed from available market data, whereas the overall rate of return is very difficult to observe or benchmark.

It is reasonable to consider ranges for each parameter as part of the estimation process. However, setting point estimates rather than ranges for each parameter is likely to provide greater certainty to investors and regulated businesses.[11] This is because setting ranges for each parameter would result in a wide range of possible values for the overall rate of return. For these reasons, it is appropriate for the rules to require the AER to set point estimates for each rate of return parameter.

The AEMC has also raised the important point that parameters within the rate of return are inter-related. There are specific examples of inter-related parameters such as the market risk premium and the risk free rate.. More generally every parameter within the rate of return is inter-related because they combine to form the overall rate of return. Ausgrid considers that it is appropriate for the rules to recognise that parameters within the rate of return are inter-related and that consistency across parameters should be considered when determining values for each parameter.[12]

Question 23 How do the outcomes with the persuasive evidence test applying at the time of the regulatory determinations in Chapter 6 of the NER differ from the NGR rate of return framework? Does the persuasive evidence test make it less likely that values of WACC parameters will be updated as quickly as under the NGR framework, or vice versa?

The persuasive evidence test has been an important component of the electricity distribution framework. It has allowed flexibility to depart from the outcomes of a WACC review where there has been a material change in circumstances. For example the gamma parameter has changed because material errors were identified in the AER's estimate of gamma in the WACC review. The AER has also departed from its WACC review estimate of the market risk premium based on its view that market circumstances have materially changed since the time of the WACC review.

At the same time, the persuasive evidence test has provided certainty that parameters adopted in a WACC review would be applied at the time of a determination where there has not been a material change in circumstances. For example, the 0.8 equity beta set by the AER in the last WACC review has been applied consistently in electricity distribution determinations since the WACC review was published.[13] Therefore, the electricity distribution rate of return framework is likely to have provided some inertia to changing WACC parameters over time. Ausgrid considers that this is a desirable outcome because it provides greater certainty about the rate of return over time, which is important for both investors and regulated businesses.

[10] AEMC Directions paper, 2 March 2012, p. 66.
[11] Ausgrid notes that in the past the AER has stated a preference for using point estimates rather than ranges. See AER, *Final decision, Review of WACC parameters*, May 2009, p. 287.
[12] See for ecample AER, *Final decision, Review of WACC parameters*, May 2009, pp. 97–110.
[13] AER, *Final decision, Queensland distribution determination*, May 2010, p. 267; AER, *Final decision, South Australian distribution determination*, May 2010, pp. 344–345; AER, *Final decision, Victorian distribution determination*, October 2010, p. 519.

Questions 24 to 28

We note that regulatory frameworks for gas and electricity have developed separately and differently. Therefore, there are specific considerations that should be taken into account when determining whether to implement a new rate of return framework for gas. We also note that the different characteristics of gas network service providers may justify using different benchmarks when setting the rate of return for gas businesses. We support the ENA's submission on these issues.

Question 29 Which rate of return framework would best meet the key attributes identified? Are there any other attributes that should be considered?

Ausgrid considers that the electricity distribution framework provides the best method for setting the rate of return, compared to the other frameworks in place. The periodic WACC review provides guidance about the rate of return that is likely to apply in network determinations and considers the latest available evidence on rate of return parameters across the energy network industry. At the same time the persuasive evidence test allows flexibility to depart from the WACC review where there is a material change in market circumstances. However, there are refinements that could be made to improve the rate of return framework for distribution.

The current electricity distribution rules require the rate of return to 'be a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing standard control services'.[14] It is true that the rate of return for investments is essentially forward looking. However, estimating the rate of return often requires relying on historical data for different parameters. At any time the best available evidence for a particular parameter may be historical based or it may be a forward looking estimate. Alternatively the best estimate may be a combination of historical and forward looking evidence. For this reason, Ausgrid considers that the regulator or the DNSP should not be constrained from considering both forward looking and historical estimates of parameters when setting a 'forward looking' rate of return.

Ausgrid notes that estimates of the rate of return that rely on purely spot rate estimates when establishing 'forward looking' estimates has been significantly complicated by abnormal market conditions following the onset of the global financial crisis. For example, the yield on 10 year Commonwealth government bonds has typically been used as a proxy for the risk free rate of return when estimating the cost of equity using the CAPM. Yields on 10 year Commonwealth government bonds have been significantly depressed due to historically high demand for Australian government bonds. This has been driven by a 'flight to safety' caused by the effects of the GFC and more recently sovereign debt concerns in Europe.[15] That is, the market for Commonwealth CGS have been influenced significantly from global impacts and therefore do not appropriately reflect an appropriate proxy for the risk free rate of an Australian regulated utility in the current circumstances.

There has been significant volatility in financial markets and, in some periods, the limited supply of these bonds compared with the current high level of global demand for them has further depressed yields. Overall this has meant that observations of Commonwealth government bonds in recent periods unlikely to be representative of the best forward looking estimate of the risk free rate. We note that despite this, the AER has chosen to apply a risk free rate using observation periods that are clearly abnormal and non-representative of the true risk free rate.[16]

Current yields on 10 year Commonwealth government bonds as a proxy for the risk free rate therefore provides one example of where purely spot rate estimates may be less reliable than historical estimates. In our view, under the current abnormal market conditions, historical yields on 10 year Commonwealth government bonds are likely to provide a better estimate for the risk free rate of return than the purely forward looking estimates provided by current yields on 10 year government bonds.

We would also argue that, if applied correctly, the current electricity distribution rules enable the AER to use long term historical estimates as well as purely forward looking estimates of parameters when estimating the 'forward looking' rate of return. We would ask the AEMC to consider whether this option is available under the current Rules framework in respect to the observation of Commonwealth Government Securities as it may have relevance for the extent to which Rules must be amended.

The current rules do not explicitly require consistency across parameters to be considered when setting the rate of return. Each rate of return parameter contributes to an overall rate of return, which makes consistency across parameters a relevant consideration when estimating the rate of return. However, specifically identifying the links between each rate of return parameter and requiring consistency based on these inter-relationships may not always result in the best

[14] NER cl. 6.5.4(e)(1)
[15] See for example RBA, *Statement on monetary policy*, February 2012, p. 49.
[16] For example, the AER's draft decision for Aurora Energy adopted a risk free rate estimate of 4.28% based on a recent short-term average of yields on 10-year Commonwealth government bonds. See AER, *Draft decision, Aurora distribution determination*, November 2011, p. 211. However, the Reserve Bank has noted that current yields on Commonwealth government bonds are at 50 year lows due to the impacts of the GFC and the European sovereign debt crisis. See RBA, *Statement on monetary policy*, February 2012, pp. 49–50.

estimate on the available evidence. As discussed above, a better approach may be for specific relationships between parameters to be considered at the time of a WACC review or a determination based on the best available evidence at that time. In Ausgrid's view the current rate of return framework for electricity distribution provides consistency across parameters because it is a relevant factor that can be considered based on the best available evidence at the time of a WACC review or at the time of an individual determination.

6 Cost of debt

Question 30 Is the benchmark DRP approach likely to overstate the prevailing cost of debt, having regard to the suggestion that the overstatement may be a reflection of shorter maturity debt leading to a higher refinancing risk for NSPs? What weight should be placed on the views of market analysts on the ability of stock market listed NSPs to out-perform their cost of debt allowances?

&

Question 32 What evidence is there that the DRP benchmark in the NER may have changed? Would it be appropriate for the regulator to specify the DRP benchmark in any periodic reviews or would it be more appropriate to specify it at the time of the determinations?

Ausgrid's view is that the current DRP benchmark, which is an Australian corporate bond with a 10 year term to maturity and a BBB+ credit rating, remains appropriate. Ausgrid recognises that recent bond issuances for privately owned utility companies have been for shorter term debt. However, this is likely due to the scarcity of long term debt finance following the GFC. Both lenders and borrowers have been reluctant to engage in long term debt finance due to the significant uncertainties introduced by the GFC.[17] Ausgrid also considers that recent shorter term debt issuances are likely to involve refinancing risk, which is significantly greater due to the scarcity of debt finance following the GFC. In addition to this, the historical evidence indicates that privately owned utility companies issue debt with approximately 10 years to maturity on average.[18] This long term financing strategy is consistent with the long economic lives of energy network assets, which can extend up to 50 years or more. Ausgrid considers that short term changes in financing practices due to the effects of the GFC (i.e. recent short term debt issuances) do not warrant moving away from a long term assumption of a 10 year term to maturity for debt finance.

Ausgrid notes that T-Corp, the principal financier of NSW government owned utilities, manages its debt with a goal of securing debt finance to 10 years. In its recent submission to IPART's determination for Sydney Water, T-Corp noted that debt issued in the four years to 30 June 2011 for the NSW government owned utilities it finances had an average term to maturity of 9.8 years.[19] This is further evidence of financing practices that are consistent with the 10 year term to maturity benchmark set in the AER's 2009 Statement of Regulatory Intent.[20]

Ausgrid considers that the benchmark assumptions of an Australian corporate bond and a BBB+ credit rating also remain appropriate based on the evidence considered in the AER's 2009 WACC review.[21] Therefore, in Ausgrid's view there is no evidence that the DRP benchmark in the NER has changed.

The current rules for electricity distribution enable the benchmark assumptions for the cost of debt to be amended by the AER either at the time of a WACC review or at the time of a determination, if there is persuasive evidence to do so. The current electricity distribution rate of return framework provides the necessary flexibility to respond to changes in the benchmark cost of debt over time while still providing significant guidance that the benchmark assumption will not be changed until there is persuasive evidence to do so. Ausgrid considers the persuasive evidence test is important because it maintains a consistent long term approach to setting the benchmark cost of debt in the absence of persuasive evidence to depart from the benchmark. This provides stability and certainty to investors and regulated businesses. Therefore Ausgrid endorses the current process for setting the debt risk premium benchmark under the current electricity distribution rules

Question 33 Is the EURCC's proposal of establishing the cost of debt using historical trailing average compatible with the overall framework for estimating a forward-looking rate of return? What are the potential benefits of using a trailing average and do they outweigh the potential costs if the estimate is less reflective of the prevailing cost of debt for NSPs?

&

Question 34 What possible changes would be required in the NER to implement the EURCC's trailing average approach?

[17] This has been demonstrated by the Financial Investor Group. See Financial Investor Group, *AEMC Consultation Papers: rule change proposals relating to the economic regulation of electricity (ERC0134 and ERC0135) and gas (GRC0011) networks*, 8 December 2011, p. 44.

[18] See for example AER, *Final decision, Review of WACC parameters*, May 2009, p. 158.

[19] T-Corp, *Submission for Sydney Water Final determination*, 24 January 2012, p. 2.

[20] Ausgrid notes that the 10 year term to maturity was assumed for the purpose of setting the risk free rate proxy and clause 6.5.2(e) of the NER requires the term to maturity for the debt risk premium to be consistent with the term to maturity for the risk free rate proxy. As a result the term to maturity for the benchmark cost of debt was also required to be 10 years.

[21] AER, *Final decision, Review of WACC parameters*, May 2009.

The AEMC has asked whether the EUC's proposed method of calculating the cost of debt as a trailing average is compatible with the framework for estimating a forward looking rate of return. The current electricity distribution and transmission rate of return frameworks require the rate of return to be forward looking.[22]

The rate of return is necessarily forward looking, because under the building blocks approach the return on capital component of regulated revenues/prices is to be earned on a regulatory asset base over a prospective regulatory period. However, in Ausgrid's view the NER requirement for the rate of return to be forward does not un-necessarily limit the consideration of historical evidence. For example, the AER has consistently relied on historical evidence when estimating rate of return parameters including the market risk premium[23] and the equity beta.[24].

Nevertheless, it has been common regulatory practice to set a risk free rate and cost of debt for a regulatory period based on a short-term observation period (between 10 and 40 days). This is based on the assumption that rate observation over a short period of time is likely to be representative of the rates that will apply to each year of a regulatory control period

However, the evidence does not necessarily support this assumption. T–Corp has noted that its analysis shows a long term average approach has a lower absolute average error than a short term (20 day) average approach when forecasting debt costs 1–2 years forward.[25] This indicates that in certain circumstances, a historical cost of debt may be a better estimate of the forward looking cost of debt than a short term average approach. Therefore, in certain circumstances, a long term historical average approach may be consistent with providing the best estimate of prevailing costs of debt for NSPs.

Ausgrid notes that the using a long term historical average estimate for both the risk free rate and the cost of debt is compatible with the current rate of return framework for electricity distribution. Clause 6.5.2 of the NER provides that the risk free rate is to be estimated using the yields on 10 year Commonwealth government bonds based on an averaging period that is:

> *(2) a period of time which is either:*
>
> > *(i) a period (the agreed period) proposed by the relevant Distribution Network Service Provider, and agreed by the AER (such agreement is not to be unreasonably withheld); or*
> >
> > *(ii) a period specified by the AER, and notified to the provider within a reasonable time prior to the commencement of that period, if the period proposed by the provider is not agreed by the AER under subparagraph (i),*

Clause 6.5.2 of the NER also states that:

> *(e) The debt risk premium for a regulatory control period is the premium determined for that regulatory control period by the AER as the margin between the annualised nominal risk free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to that used to derive the nominal risk free rate and a credit rating from a recognised credit rating agency.*

Note: In practice, the cost of debt has been calculated using the forecast yields on the benchmark corporate bond observed over the same averaging period as that used to estimate the risk free rate. This is required because of the relationships outlined below.

Cost of debt = Risk free rate + Debt risk premium, and therefore

Debt risk premium = Cost of debt – risk free rate

Because the most practical approach to estimating the debt risk premium has been to estimate the cost of debt and then subtract the estimated risk free rate, the cost of debt has been estimated over the same averaging period used to estimate the risk free rate.

To implement a long-term historical average approach to estimating the risk free rate and the debt risk premium, an NSP could propose a 10 year period over which to average estimates of the yields on Commonwealth government bonds and

[22] NER, cl. 6.5.4(e)(1) & 6A.6.2(j)(1)

[23] AER, *Final decision, Review of WACC parameters*, May 2009,pp. 236–238 and AER, *Draft decision, Aurora distribution determination*, November 2011, pp. 214–216

[24] AER, *Final decision, Review of WACC parameters*, May 2009, pp. 311–328.

[25] T–Corp, *Submission for Sydney Water Final determination*, 24 January 2012, p. 3.

forecast yields on Australian corporate bonds.[26] In our view, this would be consistent with the current rules framework for electricity distribution.

Given current market conditions, the circumstances of Ausgrid and necessary financing arrangements for a large debt portfolio, Ausgrid considers that the short-term averaging period approach currently employed by the AER results in too much risk to investors and regulated businesses. For Ausgrid in particular, this approach results in too much risk for establishing a meaningful cost of equity and a cost of debt. A short term averaging period approach results in significant variation in the regulated rate of return across relatively short periods of time. There may be circumstances where businesses are able to prudently hedge the underlying interest rate to minimise refinancing risk, but this may not be prudent in all circumstances.

Ausgrid endorses the approach of estimating both the risk free rate and the debt risk premium based on long term historical data. Specifically, Ausgrid submits that in its current circumstances it would be entirely prudent to establish the risk free rate as the 10 year historical average of annualised yields on 10 year Commonwealth government bonds. As described above, this could be implemented by adopting an averaging period for the risk free rate that is a 10 year averaging period. We understand NSW T-Corp has proposed an approach that would allow for a similar observation for corporate bonds so that a DRP could be established based on a similar 10 year historic averaging period.

While we note that it may not be appropriate for all businesses to adopt such an approach, the current rules provide the flexibility for different businesses to propose alternative approaches for establishing the observation period for the risk free rate and allow an observation period for the DRP consistent with that used for the risk free rate.

We believe this is an important issue for the AEMC to consider. The Commission was formerly of the view that the NSP was in the best position to establish the period in which the 10 year government and corporate bond rate should be observed. The AER has powers to withhold the NSP's proposed period but cannot do so unreasonably. We favour this design over one which is inflexible or open only to the AER to determine.

In respect of the specific changes required under the Rules to adopt the trailing historical average approach advocated in the EUCC Rule change, we agree with the ENA's submission that significant changes would be required to the current rules to implement such an approach.

In Ausgrid's view caution needs to be taken when establishing a method for estimating the benchmark cost of debt that is too prescriptive and as a result does not cater for differences between businesses actual debt management practices and the approach set in the rules. Such differences may create adverse incentives for NSPs to behave in a manner that is contrary to prudent debt management. For instance, an NSP with a large debt portfolio may have legitimate reasons not to hedge underlying interest rate risk over a small period of time.[27]

Under the EUC's proposed approach, the risk free rate component of the cost of debt would remain as a locked in value. However the debt risk premium component would be estimated on a trailing average basis taking into account a prevailing (annually updated) risk free rate estimate. This is described by the relationship illustrated below:

Cost of debt *= Risk free rate + Debt risk premium*

= Risk free rate + (Annually updated historical cost of debt – annually updated risk free rate estimate)

In addition to this, the risk free rate estimate in the cost of equity would also remain fixed for the regulatory period, as described by the following relationship:

Cost of equity *= Risk free rate + Equity beta × Market risk premium*

If the risk free rate estimate remains locked in at the start of a regulatory control period, then:

Risk free rate ≠ annually updated risk free rate estimate used to estimate the debt risk premium

[26] Ausgrid notes that the AER's 2009 WACC review final decision stated that the averaging period should be between 10–40 business days. However, the 2009 SORI for electricity distribution not define the term of the averaging period. In any case a departure from these elements of the SORI is warranted under clause 6.5.4 of the NER if there is persuasive evidence to warrant such a departure. In Ausgrid's view, current market circumstances would warrant a move to a long term historical observation period for the risk free rate and the debt risk premium.

[27] In this regard, T-Corp has noted that it would be extremely difficult to hedge its large debt portfolio within short averaging period. See T–Corp, *Submission for Sydney Water Final determination*, 24 January 2012, p. 3.

Therefore, the EUC's proposed approach would introduce an inconsistency in the cost of debt equation and between the cost of debt and the cost of equity components of the rate of return. This inconsistency would expose investors and regulated utilities to the variance between the locked in risk free rate and the annually updated risk free rate components of the cost of debt. Such a variance would be very difficult to hedge.

More fundamentally, the regulatory control mechanism locks in allowed revenues (or weighted average price increases) over the regulatory period using the building blocks. Allowing the cost of debt to vary annually, would be in contrast to how other components of regulated revenues are set under the building blocks framework. For example, capital and operating expenditure, as well as the cost of tax allowance are set at the start of the regulatory period.

In Ausgrid's view there are a number of issues and risks brought about by a trailing average approach over the regulatory period. A trailing average approach may expose consumers and regulated businesses to greater price/revenue volatility over the regulatory period. One aspect of the current regulatory framework is that it provides regulated businesses with a stable level of allowed revenue (or stable weighted average price increases) over the regulatory period. However, annually updating the cost of debt allowance would also change the allowed revenue (or allowed weighted average price increases) each year within the regulatory period.

We agree with the ENA's submission that before significant changes are made to the Rules, a more focussed review on the options canvassed would need to be undertaken to give stakeholders sufficient time to consider all of the implications of adopting a trailing average approach to setting the cost of debt. This would necessarily be outside the current rule change timetable.

Attachment A - Drivers of network price increases

Key findings

The AEMC's direction paper has sought further evidence on the drivers for increases in network costs. We refer the AEMC to the ENA's submission (including the NERA report) which summarises the drivers of network price increases across jurisdictions. The purpose of this attachment is to supplement the ENA submission by highlighting unique circumstances underlying Ausgrid's price increase.

The ENA's submission is confined to quantifying the impact of capex, opex and WACC. Our attachment builds on the general methodology used by the ENA to measure the impact of insufficient allowances under previous frameworks, and other compounding factors. We also document the reasons why it was imperative for Ausgrid to increase its investment program to ensure the long term safety and reliability of the network. In doing so, we show that the expenditure program has been improving reliability outcomes for our customers.

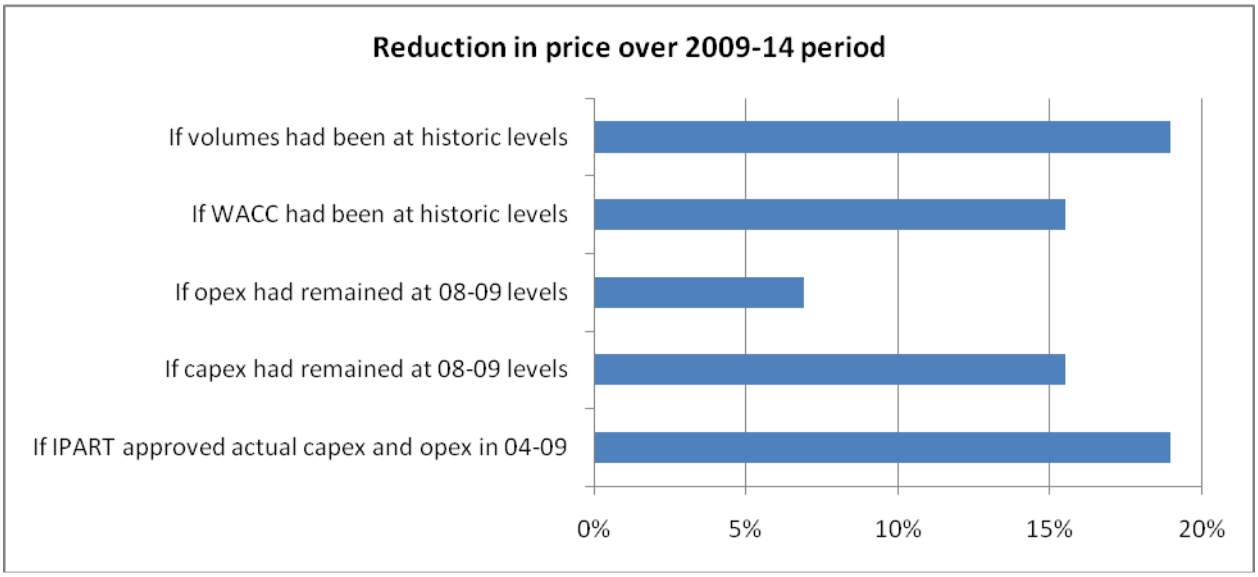
Drivers of network price increases

Our submission identifies a co-incidence of drivers that led to a significant price increases to our customers in the 2009-14 period. We show that increased investment in the 2004-09 period was a catalyst for increased network prices.

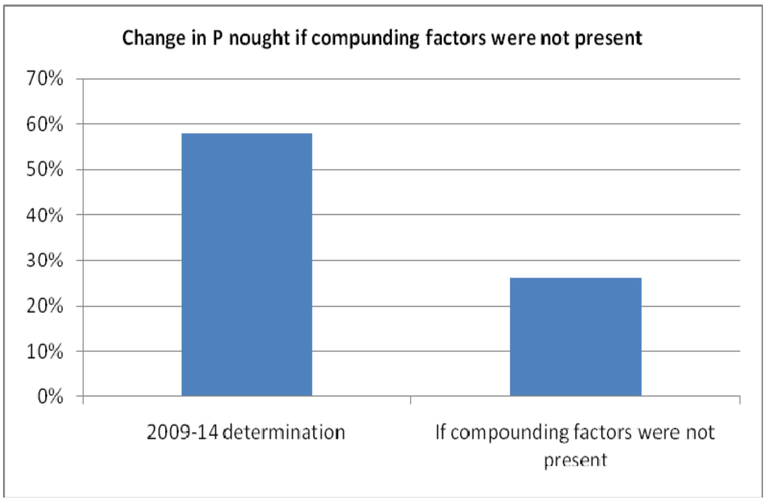
More importantly, we demonstrate that price movements were a legacy of previous frameworks which suppressed investment and prices. We also seek to highlight how declining volumes and higher cost of capital compounded the price impact. Our findings on key drivers are summarised below and explained in greater detail in section 2.

Drivers	Impact
Unsustainably low investment in previous periods	The RAB value was significantly lower than the modern day value, which meant that customers were paying relatively low prices in previous periods. If replacement had started earlier, customers would have faced a lower price impact in the 2009-14 period.
Customers did not pay cost reflective prices in 2004-09 period	Our actual capital and operating costs in 2008-09 were well above what IPART allowed at the beginning of the period. This was also magnified by Ausgrid's decision to invest more heavily in capacity and replacement expenditure, which was not reflected in the prices being paid by customers in the 2004-09 period. When prices were re-calibrated in the 2009-14 determination, customers faced a step change in prices to reflect the true costs of providing these services.
Increased costs in 2009-14 compared to 2004-09	Ausgrid's out-turn capital and operating expenditure increased sharply in the latter half of the 2004-09 regulatory control period. Capital and operating expenditure increased further from 2008-09 levels. At the same time, the cost of capital increased from its historical trend as a result of the GFC. While capex and opex increases explain some of the price movement, other factors such as the high cost of capital were key contributors to the magnitude of the price movement
Volume growth was significantly lower than historical trends	If volume growth had been at historical levels, the price impact faced customers would have been far less.

As part of this analysis, Ausgrid has sought to quantify the impacts of each of these drivers using a similar methodology to the ENA. The diagram below shows that customers would have paid significantly lower prices if each factor was not present.



The above analysis reveals that there were a number of compounding factors influencing the price movement in the 2009-14 period including lower volumes, higher WACC, and insufficient allowances compared to our actual out-turn expenditure. If these factors were not present, the P nought (change in price over period) would have reduced from 58 per cent to 28 per cent (a reduction in price of 52 per cent). Ausgrid modelled the X-factors that would have occurred if these factors were not present.



	2009-10	2010-11	2011-12	2012-13	2013-14
2009-14 determination	-17.86	-18.18	-18.18	-18.18	0.77
Amended X-factors	-9.01%	-9.00%	-9.00%	-9.00%	-5.00%

Why Ausgrid increased investment

Section 3 of this attachment provide evidence on why Ausgrid needed to increase its levels of expenditure in the latter half of the 2004-09 period, and continue this uplift in the 2009-14 period. We show that the network was suffering from high rates of failures due to the condition of assets on the network and over-utilisation of key assets. We also identify the preliminary outcomes from the investment program such as lower equipment failures and improved reliability.

1 Explaining Ausgrid's price movements

The table below identifies the X-factors for our distribution and transmission services in the 2009-14 period. The focus of our attachment is on our distribution prices given that this is the majority of network costs paid by our customers.

	2009-10	2010-11	2011-12	2012-13	2013-14
Distribution	-17.86	-18.18	-18.18	-18.18	0.77
Transmission	-7.77	-18.46	-18.46	-18.46	-2.02

In this section we provide an analytical framework for quantifying and explaining the reasons for price increases. We show that there are two reasons why prices move between periods:

a. Changes in revenue between periods

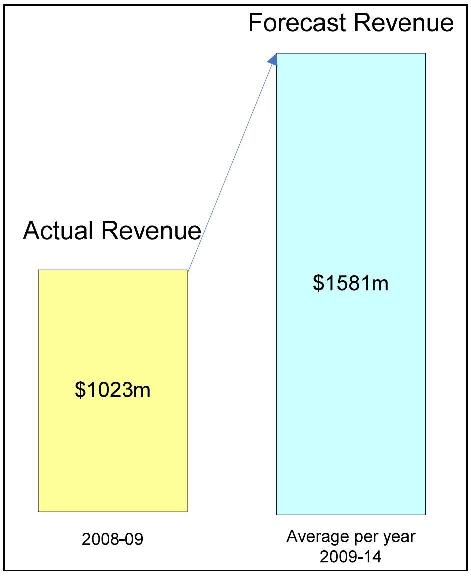
b. Growth in energy volumes (sales)

We also identify how these factors were prevalent in the price movement faced by our customers in 2009-14.

1.1 Impact of change in revenue

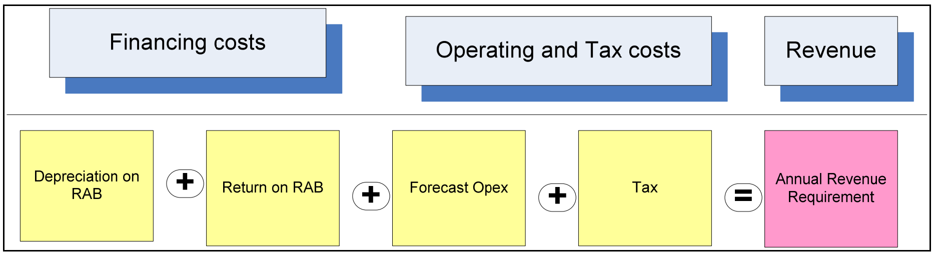
Price movements are a function of the change in revenue between periods. This is illustrated in the diagram below which shows that Ausgrid's revenue for distribution services in 2008-09 (last year of the previous period) was $1023 million, compared to the average requirement of $1581 million in 2009-14.

This meant that Ausgrid needed to collect an average 55% more each year from the customer base when we transitioned to the 2009-14 period.



How revenue is calculated

Ausgrid's revenues for each period were determined by the regulator using a building block approach. The approach calculates a revenue stream (annual revenue requirement) based on the costs that a DNSP is expected to incur in the period. These includes an allowance for financing investment (return on, and depreciation), in addition to operating and tax costs. The building block calculation is shown below.

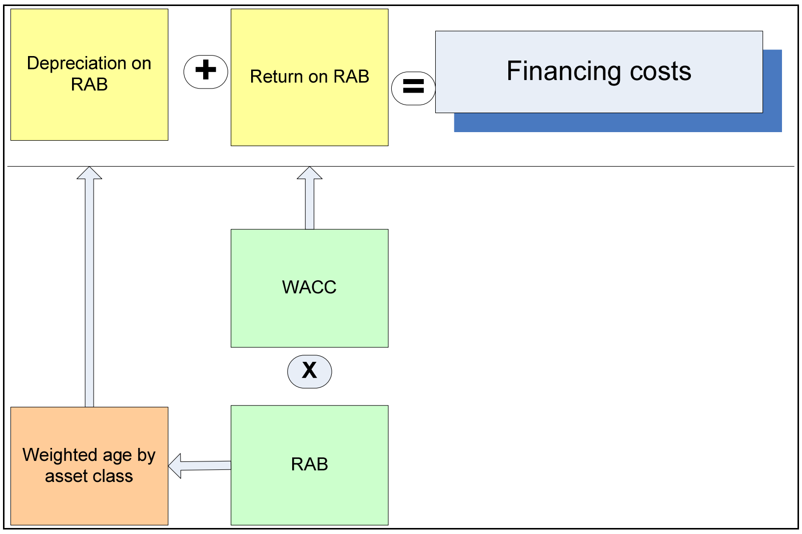


In Ausgrid's case, the forecast allowance was significantly lower under IPART's decision compared to the AER's determination. Later in the submission we show that the allowance allowed by IPART was significantly lower than the actual out-turn expenditure incurred by Ausgrid, and that this was a key reason for the magnitude of the price increase.

	IPART 2008-09 allowance	AER 2013-14 Allowance	% change
Financing cost allowance	645	1197	86% increase
Operating cost allowance	325	490	51% increase

Factors influencing financing costs

Under the revenue model, a DNSP receives revenue to fund the financing costs of an asset over its standard life. The distributor recovers the initial investment over time (depreciation stream) and earns a market return to compensate debt and equity holders. The total allowance for financing costs is determined by the value of the RAB and the cost of capital.



These factors were critical in explaining the change in price customers experienced over the period. As can be seen from the diagram, the RAB rose significantly, as did the cost of capital.

	IPART forecast in 2008-09	AER forecast for 2008-09	% change
IPART RAB at end of period	5710	10760	88% increase
Equivalent cost of capital (WACC)	8.90	10.02	13% increase

Value of RAB

The value of the RAB is the key driver to determine the financing costs allowed by the regulator. The value of RAB is influenced by:

a. The original valuation of the RAB, which is the modern day costs of assets on the network minus the estimated depreciation of assets in previous periods. The original valuation method used the age of assets as a proxy for determining the level of depreciation to be deducted from the modern day costs of assets. Given the significant age of assets, Ausgrid's RAB was set at a relatively low level.

b. New capital expenditure on assets used to provide standard control services (the asset enters the RAB at its historical cost)

c. The depreciation on assets over time (depreciation on an asset is deducted from the RAB) and the indexation of that RAB over time. [1]

In the next section we show that the value of Ausgrid's RAB was significantly below the modern day costs of building our network. This reflected the maturity of the investment cycle where we had been operating a large number of aged assets, whose value had been depreciated from the RAB. When we moved to a renewal stage of the investment cycle, customers had to fund the full financing costs of new assets.

1.2 Impact of volumes

The change in revenue only tells half of the story of why prices move between periods. The second important factor is whether the increase in revenue is accompanied by an increase in forecast energy sales (volumes). An increase in sales means that the increased revenue requirement cannot be shared among new customers, or diluted through increased energy usage (ie: a lower average price per unit)

In Ausgrid's case, forecast energy volumes were predicted to flatten to -0.1 per cent per annum average growth over the 2009-14 period. This was substantially less than long term trends of annual growth of 1.6 per cent as seen in the table below.

Time period	Average annual growth in energy
2001-2007	1.6%
2009-14	-0.1%

[1] The RAB is indexed to CPI over time, and that the calculation of depreciation is undertaken on an asset class level based on the weighted average age of the assets. There are also other minor adjustments to reflect the timing of investments and disposals.

2 Drivers of Ausgrid's price increases

In the previous section, we showed that the magnitude of Ausgrid's price movements could be explained by:

- The increase in revenue from 2008-09 (last year of previous period) to the average revenue requirement in 2009-14. We showed that the increase was 55% and this meant a large step change in revenue recovery.

- The decline in volumes. We showed that energy volumes fell from a long term trend of 1.6 per cent to -0.1 per cent in the 2009-14 period, and that this meant that the revenue recovery could not be shared amongst new customers or increased energy usage.

In this section, we seek to identify and quantify the drivers for these changes. Our key findings are identified in the table below. We show that there was a coincidence of factors that drove high network prices for Ausgrid's customers.

Drivers	Impact
Unsustainably low investment in previous periods	Revenue collected off customers in 2008-09 was very low
Customers were not paying cost reflective prices in 2004-09 period	
Increased expenditure in the 2009-14	Revenue forecast in 2009-14 was higher than 2008-09.
Volume forecast were expected to fall as a result of the impact of the price impact of the CPRS and network prices.	Volumes were lower in 2009-14

Methodology used to quantify the impact of drivers

We have used a similar methodology to the ENA submission to quantify the price impacts of drivers. Similar to ENA, we have calculated the price increase as if all price increases had occurred in Year 1 (the 'P nought'). This shows that the price increase was 58 per cent over the period for distribution services. We have then considered the impact on P nought for each factor in isolation, keeping the other factors constant.[2]

Our results differ from the ENA submission as a result of addressing factors that are particular to Ausgrid's circumstances. [3]

2.1 Unsustainably low investment in previous periods

Until 2006, Ausgrid was undertaking very low levels of replacement expenditure. In effect, we were operating the network with assets that were approaching the end, or had exceeded their standard life (ie: we were sweating the asset base). Below we show that:

- When a DNSP operates the network using older assets, customers pay a low level of revenue as a result of a lower RAB.

- Replacement expenditures in the 1990s and 2000s were at an unsustainable level which kept revenue requirements low over that period. We show that the delay in investment accentuated the price shock faced by customers.

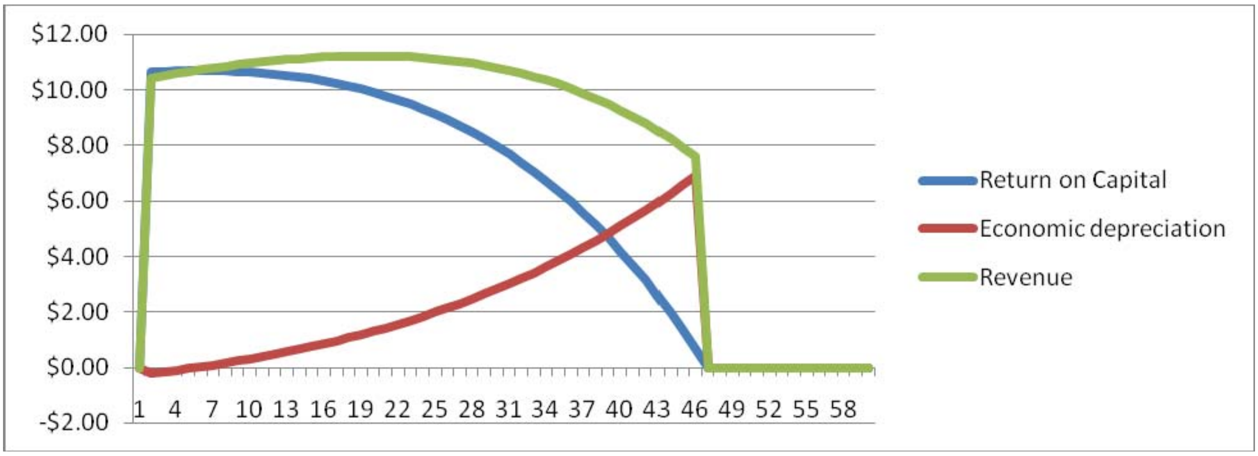
Ausgrid's revenue was at a low level

In section 1, we showed that the value of the RAB is a key input to calculating the revenues that a DNSP should receive. The value of the RAB determines the return on and depreciation allowances in a regulatory period.

[2] That is, the analysis is not additive in that each factor cannot be added to estimate the reason for the 58 per cent increase in prices..
[3] For instance we have calculated the impact of capital expenditure differently to the ENA. We estimated the impact of the overspend in 2004-09, and separately calculated the impact of the increase from actual capital expenditure in 2008-09. We consider that this method of calculation was more appropriate to explain the movement of Ausgrid's prices between periods.

The value of Ausgrid's RAB in 2004-09 was significantly depreciated compared to its modern day value of $30 billion[4]. IPART forecast that the RAB at 2008-09 would be $5710 million, less than 20% of the modern day costs of building the network. At the time of the 2004 IPART determination, Ausgrid advocated an increase in the 1998 RAB valuation to reflect legitimate unrecognised assets. IPART rejected Ausgrid's submission, resulting in the value being understated by approximately $450 million (1998 dollars). This suggests that the RAB value was at too low a level for the assets on the network.

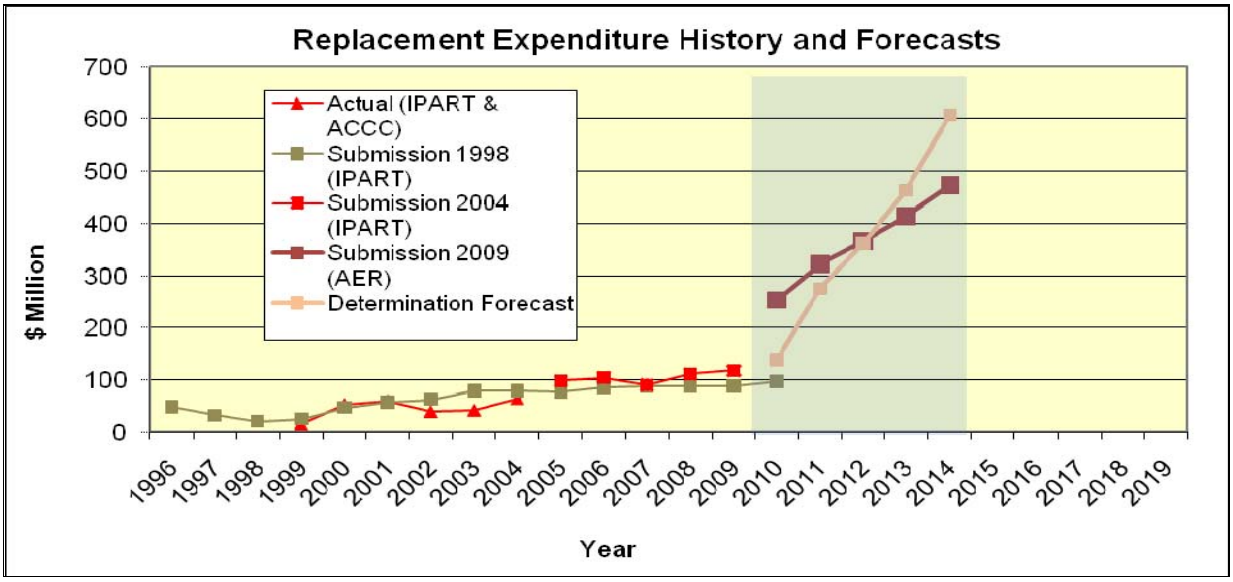
Irrespective of valuation issues, a low 'RAB to replacement value' indicates that Ausgrid was operating its network using a large proportion of assets that were close to, or had exceeded their asset life. Under the AER's revenue model, a DNSP receives lower financing costs as the asset approaches the end of its financial life, and thereafter does not receive a return on the investment. This can be seen in the following diagram which shows the return on a single asset valued at $100 million over its 45 year life.



Replacement expenditures were too low in the previous period

Ausgrid contends that the level of replacement should have been higher in the late 1990's to 2000. A more sustainable allowance would have gradually increased the value of the RAB (and prices) thereby avoiding the price shock that ensued from a period of under-investment.

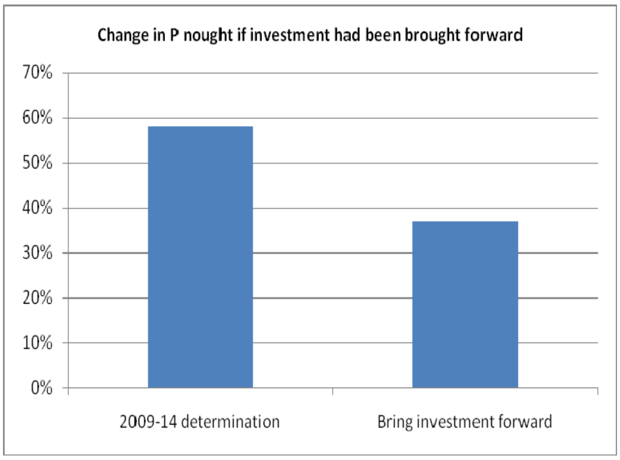
This can be seen in the following diagram which shows that replacement expenditure over the 1990s to 2000s were less than $100 million a year, for a network that would cost $30 billion to re-build. To some extent, the low levels of replacement were a consequence of effective asset management which sought to keep aged assets in service through a condition based maintenance regime. However, we show in section 3 that there was considerable evidence of failures occurring on the network, and that a more sustainable allowance would have enabled a more smooth transition to the renewal phase of the investment cycle.

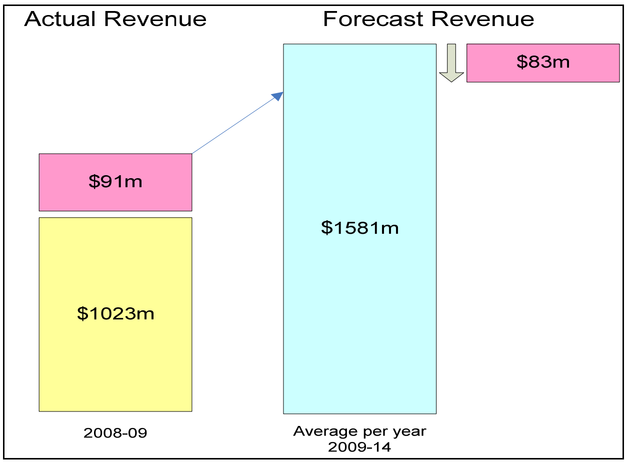


[4] Ausgrid estimated a value of $30 billion at the time of its June 2008 proposal.

A more sustainable replacement program would have resulted in a smoother price transition for customers in the 2009-14 period. Ausgrid modelled a scenario which analysed the price impact in 2009-14 where half the investment program approved by the AER was brought forward to the 2004-09 period.

The results show that Ausgrid's customers would only have incurred a P nought of 37per cent rather than 58 per cent (a reduction in prices of 36 per cent). This is because revenue collected in 2008-09 would have been higher by $91m, and the revenue to be collected in 2009-14 would have been lower by $83 million. As a consequence the price increase when transitioning to the new period would have been far less. This can be seen below.



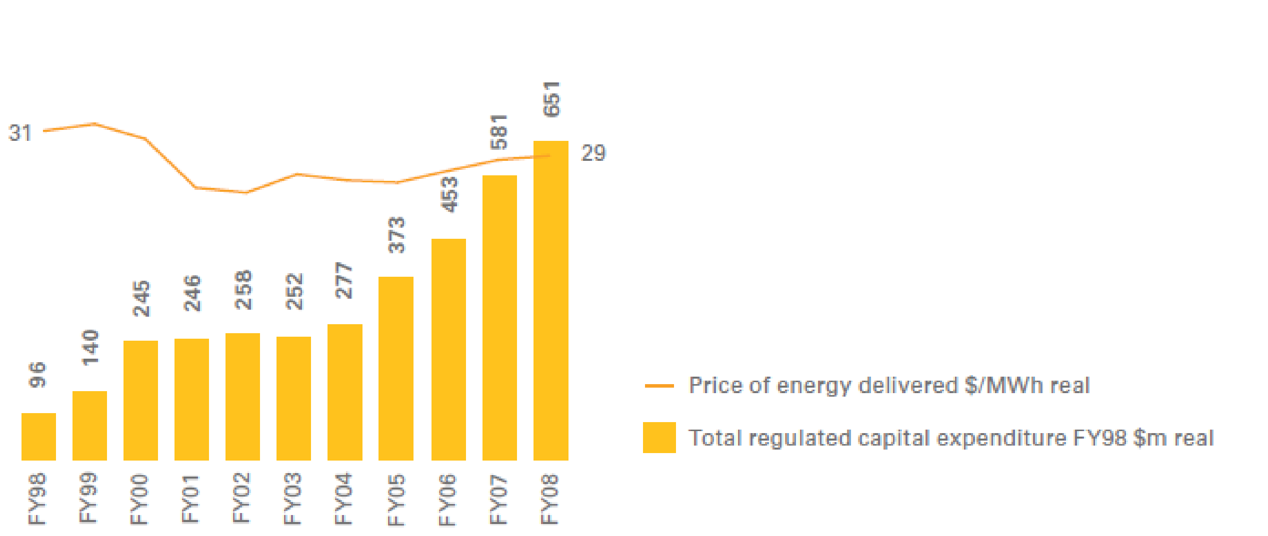


2.2 Customers were not paying cost reflective prices in 2004-09 period

There is evidence to indicate that the previous framework suppressed revenues below the efficient costs of operating the network. The implication was that the revenue collected by Ausgrid in 2008-09 was below our actual capital and operating costs in 2008-09. When prices were re-calibrated in the 2009-14 determination, customers faced a step change in revenue to reflect the true costs of providing services.

Ausgrid's regulatory proposal in 2008 provided evidence to show that real prices were declining as capital expenditure increased.

Figure 1.3: Total regulated capital expenditure versus price of energy delivered



There were two reasons why the 2008-09 revenue was below our actual costs

Lower allowances than actual expenditure

IPART and the ACCC reduced capital and operating expenditure allowances significantly from that proposed by Ausgrid. IPART reduced capex by 8 per cent and opex by 6 per cent from that proposed by Ausgrid for distribution assets. The ACCC reduced capex by 19 per cent and opex by 8 per cent for transmission assets.

Further, Ausgrid significantly spent more than its allowance (and its own proposed expenditure in the 2004-09 period), which was not reflected in the revenue requirements for 2008-09. This relates to a significant ramp up in expenditure in 2006 to meet condition issues with older assets on the network, and to commence work to meet new licence conditions by 2014. Section 3 provides evidence to show why Ausgrid considered it necessary to ramp up expenditure from 2006 onwards.

Artificial suppression of prices by IPART

IPART reduced the X-factors so that Ausgrid could not collect the revenue determined under the building block approach. This was noted by IPART in the 2004 determination where it stated:

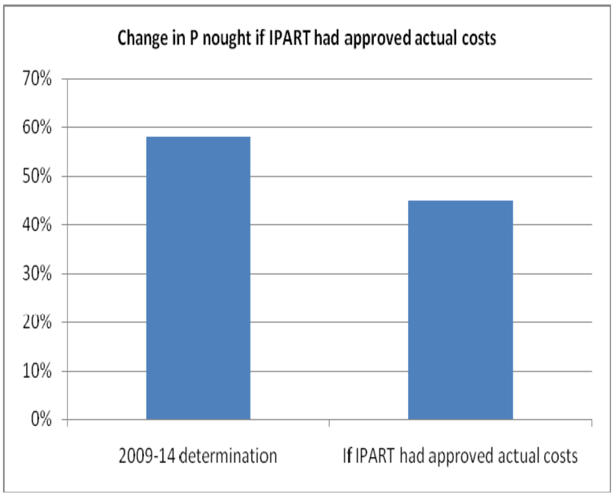
> "… the Tribunal has determined an appropriate price path that balances the interests of the DNSPs and their owner with the interests of customers. This involves targeting a 'smoothed' annual revenue requirement, so that the resulting price changes are spread more evenly over the regulatory period and/or constraining price changes to avoid stakeholder outcomes that are unacceptable under the Code.… the National Electricity Code does not explicitly require the Tribunal to take an NPV neutral approach. Rather, it requires it to have regard to a number of matters (including a sustainable return for DNSPs), and to use its discretion to balance competing issues such as equity and price stability to seek to achieve the range of outcomes listed in Clause 6.10.2 of the Code."

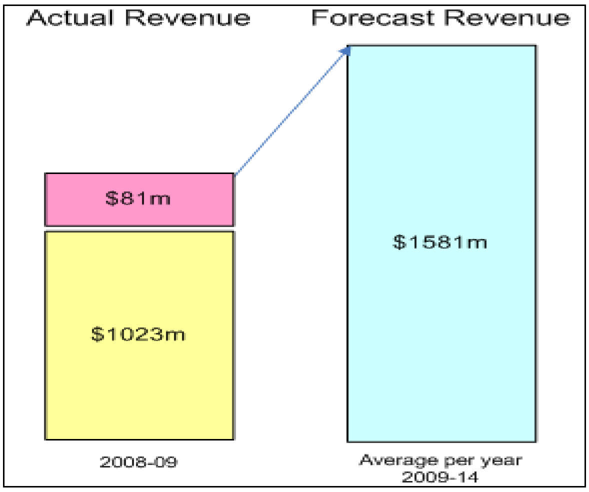
In the case of Ausgrid, IPART reset prices for Ausgrid using a constant price escalator for years 1 to 4 of the period. In doing so, IPART ignored the fact that the NPV of its proposed prices were much lower than the NPV of its price increases, thereby lowering prices below where they needed to be. Around $50 million in value was lost by Ausgrid as a result.

IPART's decision to artificially suppress X-factors below efficient levels was a key driver in the change in the prices when transitioning to the 2009-14 period. It means that the price burden was passed onto future generations.

Price impact

Ausgrid has modelled what the price impact would have been if the revenue requirements in the 2004-09 period reflected our actual costs in the period. The diagram below shows that the price increase in the 2009-14 period would have been 47 per cent instead of 58 per cent (a reduction in prices of 19%). This is explained by the fact that revenue collected in 2008 would have been higher by $81 million, and therefore a lower price movement would have occurred when transitioning to the 2009-14 period.





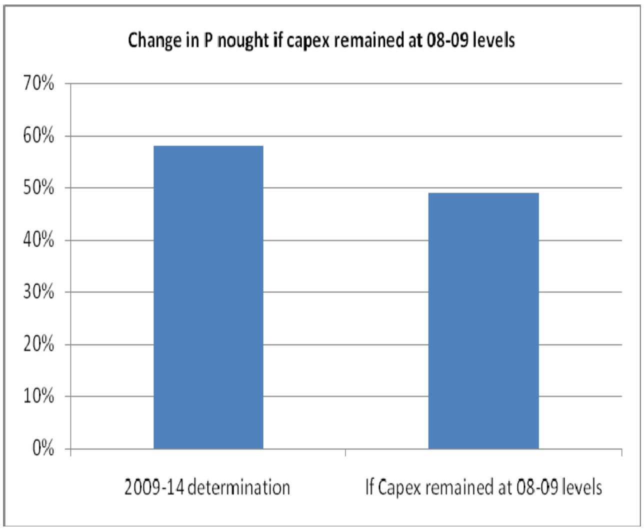
2.3 Increased forecast expenditure and high cost of capital in 2009-14 period

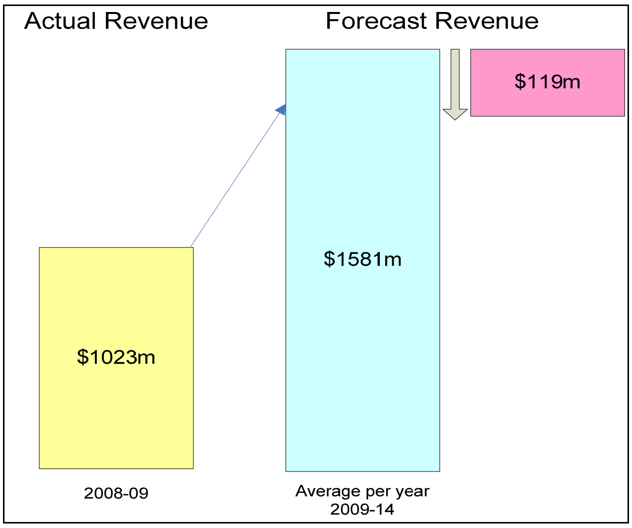
Ausgrid's capital and operating expenditure allowances in the 2009-14 period increased by 57% and 13% respectively from actual levels in 2008-09 period. This continued the ramp-up in expenditure required to replace deteriorating assets on the network, and to meet new reliability license conditions.

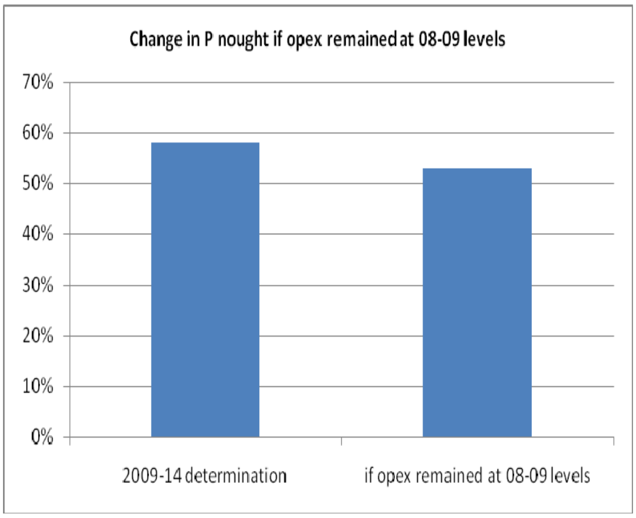
The diagrams below show that higher capex and opex (compared to 2008-09 actual expenditure) contributed to the price increase. It shows that if the AER had determined a capital allowance similar to the 2008 allowance, the P nought would have been 49 per cent rather than 58 per cent (a reduction in prices of 16 per cent). This is because the revenue required in the 2009-14 period would have lower by $119 million, resulting in a lower price movement.

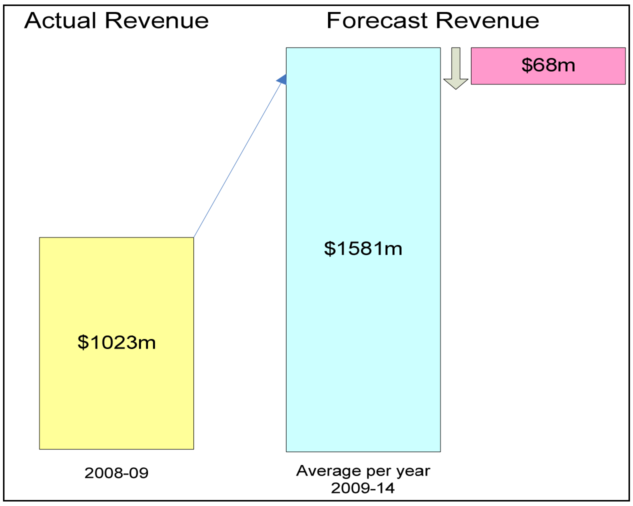
Similarly if the AER had determined an opex allowance similar to 2008 actual expenditure, then the P nought would have been 54% instead of 58% (a price reduction of 7 per cent). In this case, revenue would have lowered by $68 million in the 2009-14 period.

This shows that the ramp up in expenditure in the 2009-14 period compared to actual levels in 2008-09 was not the sole driver of the price increase, and that customers would still have paid a significant uplift in prices if the AER had provided an allowance similar to actual levels in 2008-09. Section 3 provides more details on why Ausgrid needed to increase its investment program.





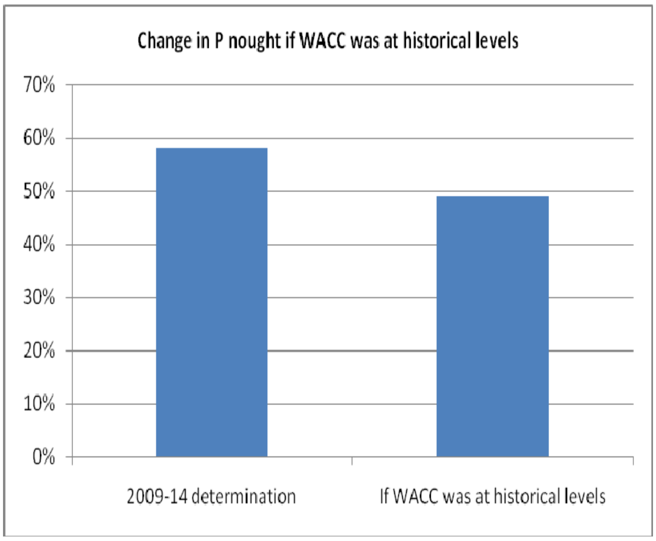


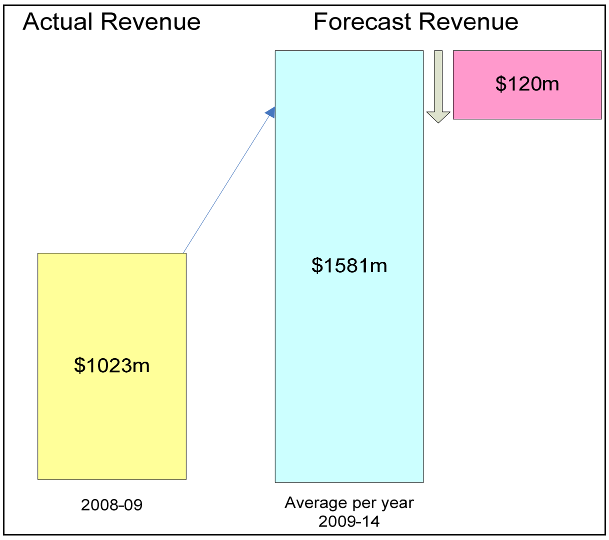


Impact of financial crisis on cost of capital

In Section 1, we showed that the cost of capital (WACC) is a key input to determining the revenue that a DNSP receives for its assets. The cost of capital was significantly higher than historic levels at the time of the AER's determination in 2009-14. This was a result of the high costs of debt and equity at the time of the AER's determination for Ausgrid as a result of the global financial crisis. The implication is that Ausgrid required a higher return on its assets to effectively fund its increased capital requirements, further magnifying the price increase faced by customers.

Below, we have sought to quantify the price impact from a higher cost of capital in the 2009-14 period (10.02 per cent) compared to the WACC based on historical trends (9.08%). This shows that the price nought would have been 49% instead of 58% (a price reduction of 16%). This is because the revenue required in the 2009-14 period would have been lower by $120 million, resulting in a lower price movement when transitioning to the 2009-14 period.



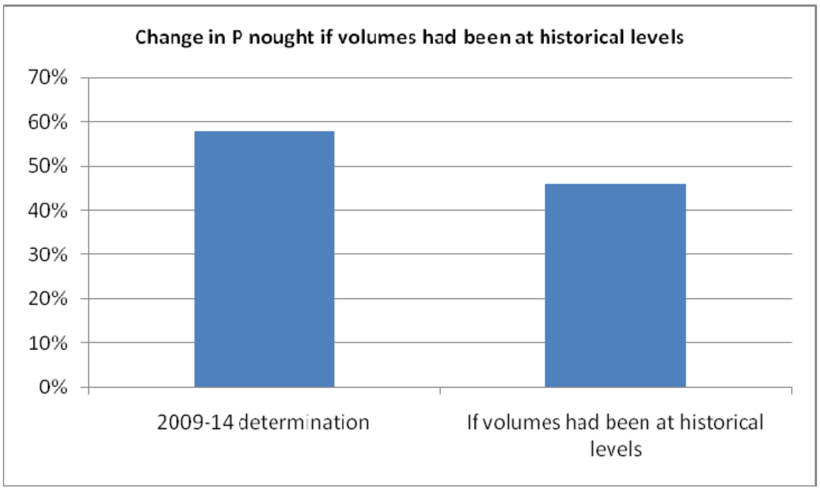


We refer the AEMC to the submission of the ENA which show that the cost of capital in the 2009-14 period was appropriate at the time of the determination. We note that the issue was extensively examined by the Tribunal who re-made the AER's determination to reflect a higher cost of capital.

2.4 Change in Volumes

Ausgrid's final determination forecast volume growth of -0.1 per cent, which was significantly below the long term trend of 1.6 per cent growth per annum. The AER's final decision reflected the fact that energy conservation programs and changes in electricity prices as a result of CPRS and network prices would lead to negative growth in energy sales over the period. It should be noted that actual energy sales in 2009-10 and 2010-11 have been even lower than that forecast by the AER.

The diagram below shows that the P nought would have been 47 per cent rather than 58 per cent (a reduction in prices of 19 per cent) if volume growth had been consistent with long term trends.



2.5 Summary of findings

The preceding analysis show that increased expenditure in the 2004-09 period and 2009-14 period were a key driver of price increases. However, the magnitude of the price increase was affected by previous regimes which focused on price suppression rather than providing a sustainable and cost reflective investment allowance. We also showed that other coincidental factors increased the magnitude of the price increase, in particular the high rate of finance as a result of the GFC and the decline in volumes from historical levels.

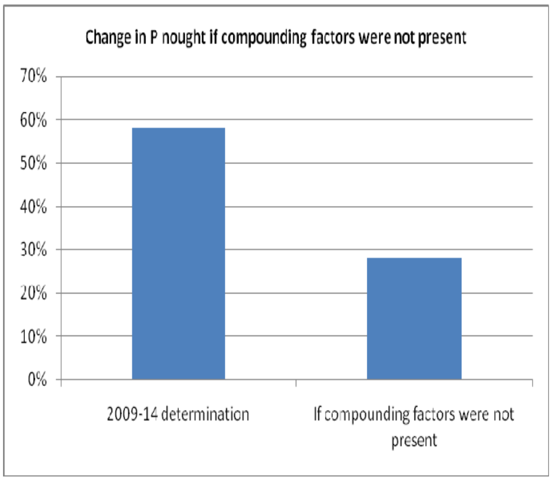
Our key findings are summarised in the table below, which is also graphically represented at the beginning of the attachment.

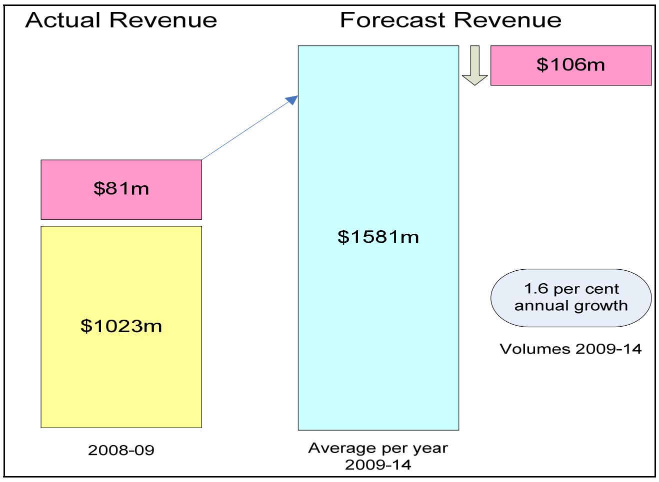
Event	Reduction in price over the 2009-14 period
If IPART had approved our actual capex and opex in 2008-09	19%
If capex had remained at 2008-09 levels	16%
If opex had remained at 2008-09 levels	7%
If WACC had remained at historical levels	16%
If volumes had remained at historical levels	19%

Isolating the impact of capex and opex

Ausgrid also analysed the price impact if the AER determined the same level of capex and opex in the 2009-14 determination, but where other coincidental factors did not occur. In undertaking this scenario we increased volumes to historic levels, reduced WACC to historic levels, and assumed that IPART had approved our actual capex and opex in 2004-09.

Under this scenario, the P nought would only have been 28% rather than 58% (a reduction in price of 52%). The revenue in 2008-09 would have been higher by $81, and the revenue would have been lower in 2009-14 by $106 million. Combined with increasing volumes, this meant that the price impact would have been significantly lowered.





We also show that the removal of coincidental factors would have dramatically lowered the X-factors, despite the same level of capital and operating expenditure.

	2009-10	2010-11	2011-12	2012-13	2013-14
2009-14 determination	-17.86	-18.18	-18.18	-18.18	0.77
New X-factors	-9.01%	-9.00%	-9.00%	-9.00%	-5.00%

3 Why Ausgrid increased investment

In the previous section, we noted that the ramp up in expenditure in 2006 was a key driver of the change in prices. Prior to 2006, Ausgrid was at a mature stage of the investment cycle where it was operating aged assets at a relatively low cost to customers. After 2006, Ausgrid entered a renewal stage of the investment cycle which required a significant increase in the investment program, and consequential operating expenditure. This led to a higher cost to service customers as a result of increased financing costs from a higher RAB.

The purpose of this section is to provide the AEMC with an understanding of why Ausgrid increased expenditure since 2006, and why the rate of growth continued in the 2009-14 period. In effect we show that after a period of investment suppression, that the long term safety and reliability of the network was under threat. This precipitated a ramp up in the investment program to address aging assets and utilisation issues.

We note that the Expert Panel report submitted by the ENA in the initial consultation phase of the proposed Rule provided evidence to show that the AER and its consultant (Wilson Cook) deeply engaged with the material provided in the proposal, and accepted that it was necessary for Ausgrid to undertake the proposed investment over the 2009-14 period. We have therefore not re-addressed this issue.

3.1 The condition of our network in 2006

In the initial years of the 2004-09 period it was apparent that there were impending security, safety and reliability issues emerging on the network that would require a significant ramp up in expenditure. This included condition issues associated with aged and deteriorating assets, and over-utilisation issues. Each are discussed below.

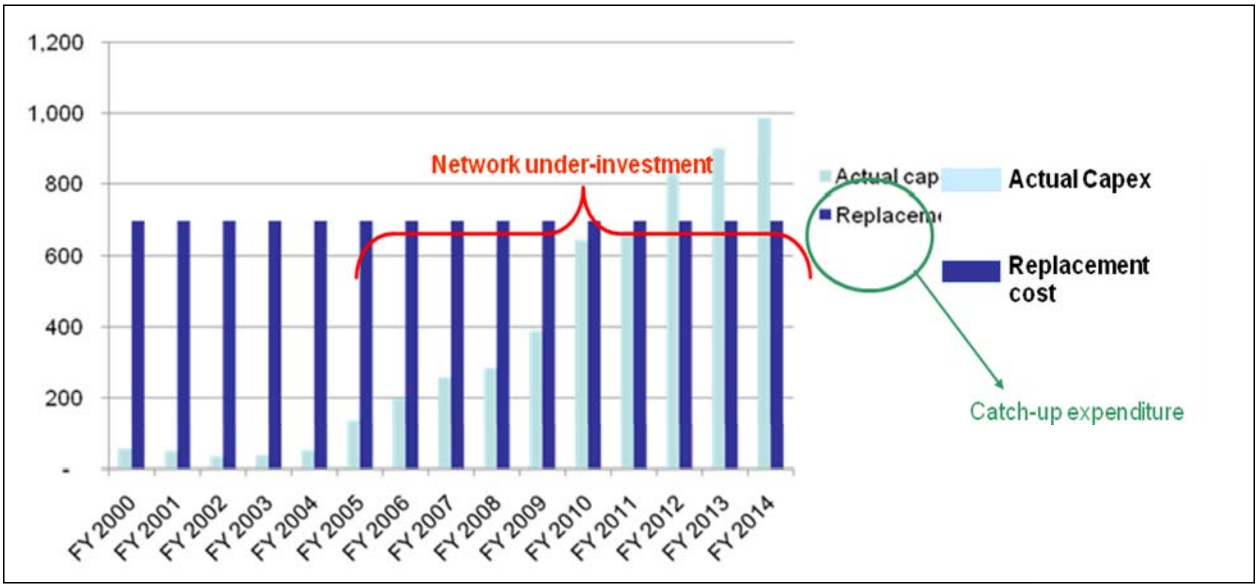
Aged and deteriorated assets

Prior to 2006, a significant proportion of Ausgrid's assets were approaching or beyond their standard life. This can be seen from the following table which shows that in 2006, a significant amount of assets were over their theoretical standard life and that this was prevalent in all categories. In particular, Ausgrid was operating critical equipments such as transmission feeders and substations above their standard life.

	Standard life	Weighted average age	Assets over standard life
Transmission substations	46	31.58	22.8%
Zone substations	46	32.24	15.4%
Distribution substations	43	24.44	12.1%
Transmission overhead feeders	50	35.86	14.8%
Transmission underground feeders	52	40.90	15.0%
Distribution feeders	49	29.65	11.7%
Total	45.68	27.36	12.3%

In section 2, we noted that allowances for replacement had been lower than required to sustain the network, and that this was the reason why Ausgrid had been operating assets beyond their standard life. While this can be attributed to effective asset management including effective maintenance programs, it is also clear

This can be seen from the following diagram which assumes that a $30 billion network would require, on average, a continual renewal of $700 million, assuming a 42 year life. However, the actual replacement expenditure in the early to mid 2000s was significantly below this amount.

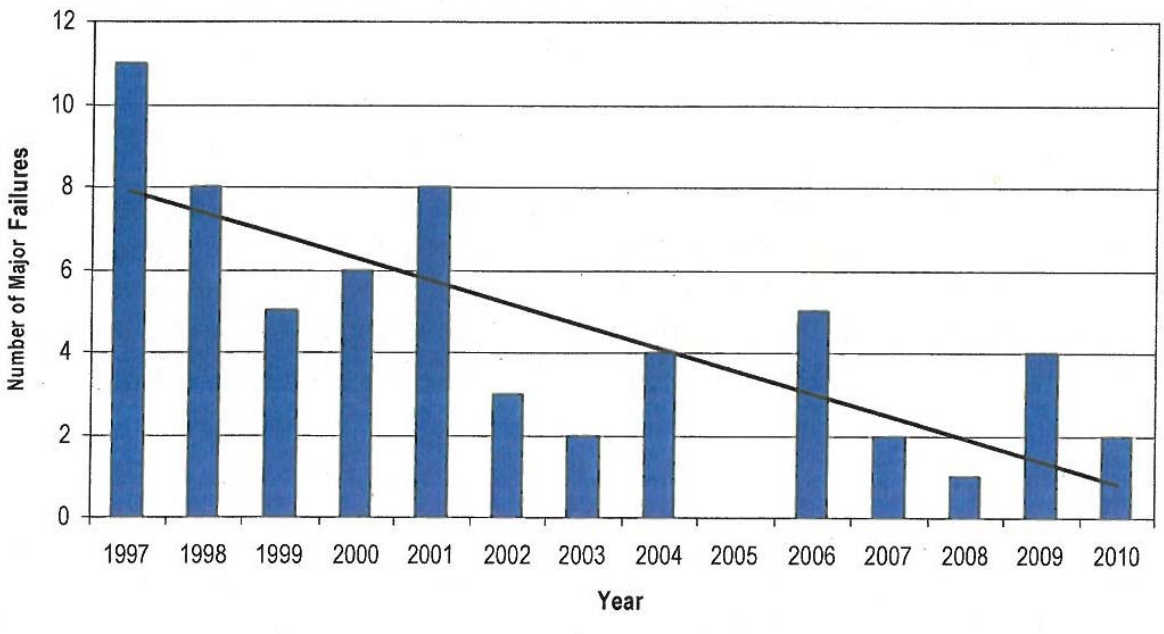


The age profile of Ausgrid's network reflects the installation of significant quantities of assets in the 1960s and many of these assets were expected to reach or exceed their useful life in the 2004-09 period. Ausgrid recognised this in its 2004 regulatory proposals. Both the IPART and ACCC determinations however significantly reduced replacement expenditure from the level contained in Ausgrid's 2004 regulatory proposals.

In the course of the 2004-09 period, it became further apparent that the aging of assets on the network was causing safety and reliability issues, and that the problem would worsen over the upcoming years. In particular, we were experiencing increased levels of reactive replacement due to asset failure and condition.

The following diagram shows that major substation failures were occurring at an average high rate between 1997 and 2006. The rate of failure started to decline when Ausgrid implemented effective maintenance programs in the early 2000s but this was insufficient to arrest the deterioration of assets caused by age.

Figure 1 – Major asset failures in zone or sub-transmission substations

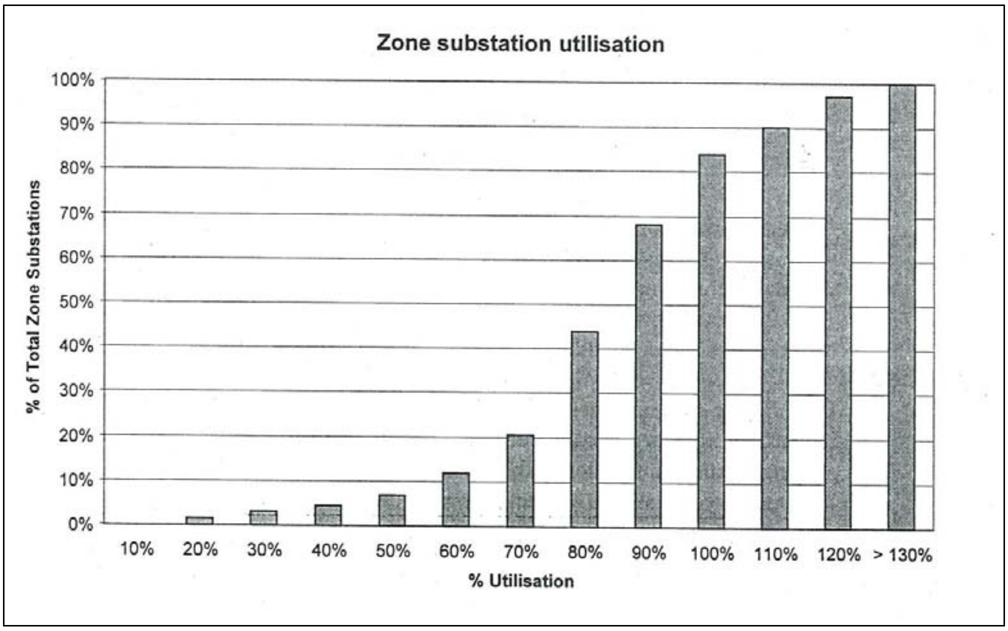


An example of a critical incident was the explosion of circuit breakers at our Mason Park sub-transmission substation in 2006. A case study is provided at Appendix A that was provided to the AEMC in the 2006 transmission review to show how the previous framework had not allowed Ausgrid expenditure to replace this asset before it failed.

Capacity issues

In our 1999 proposal we alerted our regulators to the excessively high utilisation levels across our asset base, which were creating a risk to ongoing security of supply of the network. This extended to critical assets on the network.

In our 1999 proposal, we noted that 12 per cent of sub-transmission substations were above their firm rating and that another 25 per cent were at 90 per cent of utilisation. Similarly we noted that zone substation were above their firm rating and that 30 per cent of the total population were at 90 per cent or above utilisation. This can be seen in the graph below.



As we headed into summer of 2005, there were 108 front line sections of 11,000 Volt cables or feeders that were over-utilised in the Sydney and the Central Coast. It is almost certain that there were other sections of cable that were also operating above their capacity.

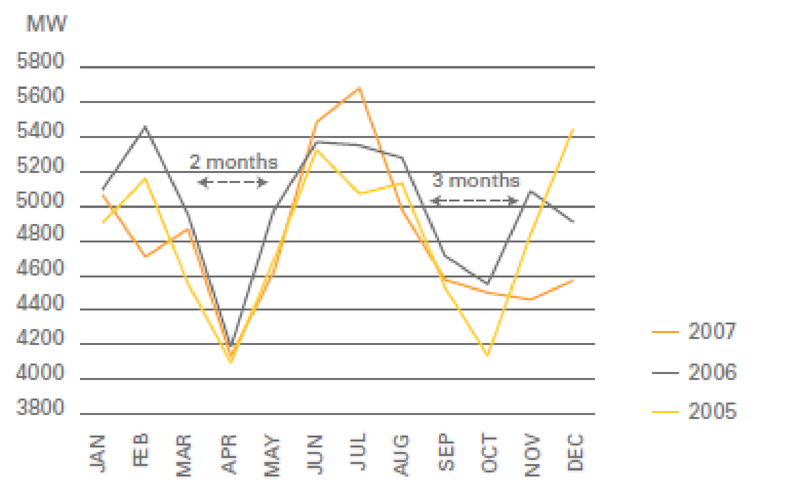
3.2 Catalyst for increased investment requirements

Several factors at the beginning of the 2004-09 period prompted a change in focus from increased asset utilisation to arresting the trend of declining network performance. The outcomes of the Somerville report into power shortages and reliability problems in Queensland were a key catalyst for change among distributors. We were more conscious of the significant risk of operating a network beyond its capacity.

During the early parts of the 2004-09 period we also realised that the build up of replacement requirements would mean that there was a only a short window period to commence the replacement program, or face the prospect of building expensive overlay networks to provide continued supply to our customers. This was explained in our 2008 proposal:

> “EnergyAustralia now faces only two blocks of two to three months each year where major equipment can be taken out for maintenance or repair while still maintaining security of supply to customers. These windows are narrowing over time and are expected to diminish further within 10 years in the absence of major investment.”

Figure 5.6: EnergyAustralia network peak demand by month



Below, we show that our focus was on arresting the deterioration of assets on our network and meeting new licence conditions imposed by the NSW Government.

Replacement of aged and deteriorated assets

In light of aging networks and high failure rates, Ausgrid started to developing frameworks and data models to identify issues on the network, and plan long term sustainable replacement programs.

- We installed improved data systems to enable us to move from an age based replacement program to an actual condition and risk based approach.
- We developed ‘best practice’ methodology to determine replacement requirements based on the likelihood of failure and the consequence of failure.
- We assigned specialist investment managers for specific asset portfolios. The managers monitored failure rates and modes on our assets, and identified assets which have emerging issues. This was overseen by a specialist committee.

Ausgrid’s approach enabled a methodical and informed approach to making replacement decisions. We have provided a case study at Appendix B (confidential) for the AEMC to review. This was provided to the AER’s consultant (Wilson Cook) at the time of the 2008 determination and shows the rigorous approach Ausgrid undertook to review the replacement program for 33kV circuit breakers. The comprehensive report provides a useful case study on how Ausgrid made its investment decisions including the following approaches.

Ausgrid’s approach	Summary of approach
Failure history	We identified all failures of the asset class, and identified the mode and consequence of that failure
Risk ratings	We assessed the likelihood and consequence of the failure in accordance with a standard risk matrix
Replacement options	We identified 5 replacement strategies based on addressing the particular need
Unit rates	We used the 2 most recent replacement projects to estimate the costs of replacing the assets
Prioritisation	We developed a scorecard framework to individually assess the risk of each asset on the network

Capacity investment to meet DRP licence conditions

In August 2005, Ausgrid became subject to new licence conditions. The impetus for licence conditions appears to be network reliability issues and consequential reviews of DNSP performance in other jurisdictions (including the Somerville report). The reviews highlighted the need for government to establish minimum service standards for networks to prevent long term issues with security and safety of supply.

The licence conditions required Ausgrid to invest to meet

1. Design criteria including enhanced redundancy (N-2) in the CBD, and risk-modified deterministic criteria for other elements and areas of the network.
2. Reliability output performance measures which provided for progressive and significant reductions in frequency and duration of outages
3. Individual feeder reliability standards, which required investment to monitor and address reliability shortfalls for poorly performing distribution feeders. .

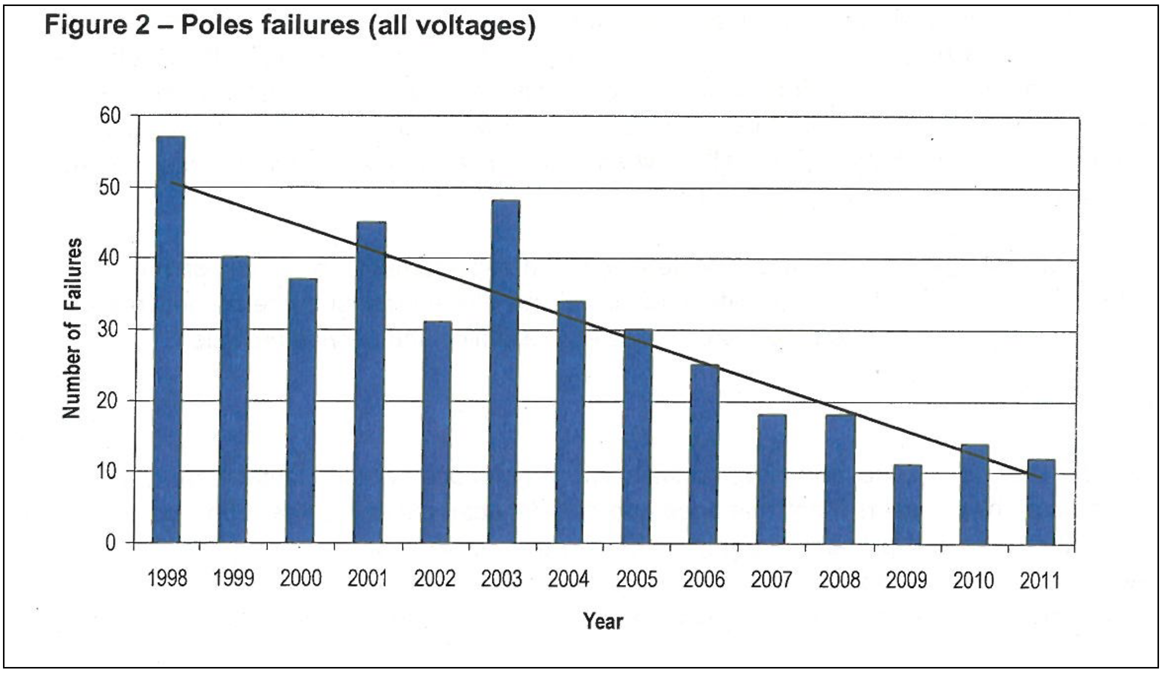
Ausgrid would need to commence investment in 2006 to achieve licence compliance by 2014. This was confirmed by IPART's assessment of Ausgrid's pass through application in 2006.

3.3 Outcomes of investment to date

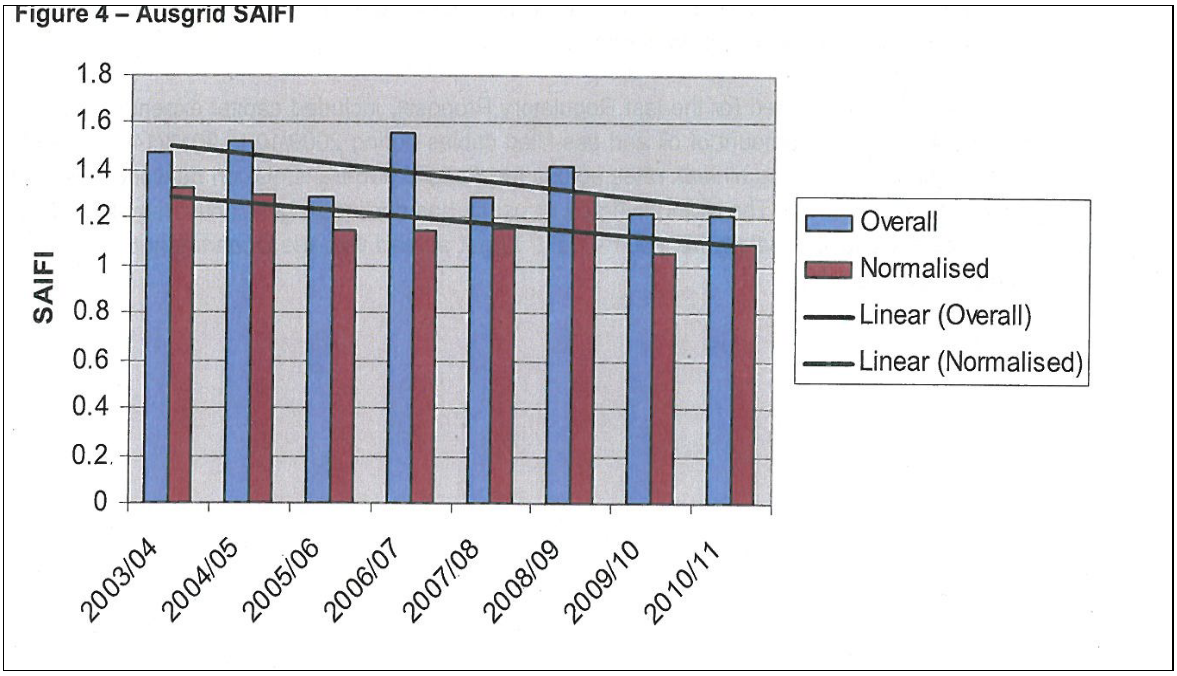
There is clear evidence to show that the investment is starting to improve system performance to sustainable levels. However, there are still a considerable number of assets that continue to age on the network over time. Below, we have provided snapshots of how the decline in network performance is being arrested by the investment program.

Indicators	Improvement
Average number of blackouts from equipment failure	The average number of blackouts from equipment failure has been cut by about 12% between 2003/04 to 2010/11.
Failures of major substations	In 2001 there were eight significant failures at major substations. Last year, there were two major failures.
11kV feeder above rating capacity	In 2005, there were 108, 11 kV feeders over rating capacity in Sydney and the Central Coast. Now there are 44.
Pole failures	In 2001, there were 45 poles failures. Last year, there were 13.
Average failures of rural power lines	The average number of blackouts caused by rural power lines has been cut in half over the same period.
Maintenance costs	Maintenance costs have reduced by 4 per cent.

As an illustration, Ausgrid notes that programs such as its pole maintenance and replacement show that effective asset management are reducing failures.



Further the reliability output measures driven primarily from government licence conditions have provided progressive and significant reductions in frequency and duration of outages. This can be seen below.



Appendix A to Attachment A - Extract from EnergyAustralia submission to 2006 Rule change on transmission revenue regulation

Background

In 2005, the ACCC set a revenue cap for EnergyAustralia's transmission network. This revenue cap decision was made under the "consider-determine" model. This framework requires the regulator to second guess the network's planning decisions. This case study highlights the impact of this framework on EnergyAustralia's capital replacement policy.

Revenue Cap Application

EnergyAustralia proposed a reasonable capital replacement program requiring expenditure of $156m over the regulatory period (2004–2009). The application was based on EnergyAustralia's capital replacement policy, which is designed to control the percentage of assets that have an age exceeding the standard regulatory life of that class of asset.

Under this policy condition monitoring for specific classes of assets is used wherever possible. A condition and risk assessment (CRA) methodology is used to assess the failure risk of all operating items, which are then given a rating prepared using the matrix shown in Table 1.

Table 1 – EnergyAustralia's risk assessment matrix

	Likelihood	Consequences 1 Insignificant	2 Minor	3 Moderate	4 Major	5 Catastrophic
A	Almost certain	A1	A2	A3	A4	A5
B	Likely	B1	B2	B3	B4	B5
C	Possible	C1	C2	C3	C4	C5
D	Unlikely	D1	D2	D3	D4	D5
E	Rare	E1	E2	E3	E4	E5

Risk rating:

Extreme	Immediate action required
High	Senior management attention required
Moderate	Management responsibility must be specified
Low	Manage by routine procedures

Each asset is given a risk rating for

- less than five years;
- between five and ten years; and
- between 10 and 20 years.

As the network planner, builder and operator EnergyAustralia considered what these ratings could possibly mean for safety, network reliability and network security. EnergyAustralia's replacement program was then developed based on this risk assessment. The revenue cap application included replacing assets with a risk rating of "C2".

The ACCC decision

The ACCC, under the "consider-determine" model, was required to review EnergyAustralia's proposed replacement program, which led it to review the replacement policy. The ACCC, while being an economic regulator, was forced to make a decision on a highly technical engineering matter, for which EnergyAustralia is held accountable.

Based on advice from engineering consultants, the ACCC decided that the assets classified as having a risk rating of "C2" should not be included in the revenue cap. The result was that EnergyAustralia did not receive funding to replace these assets.

Failure of consider-determine

On 20 July 2006, a circuit breaker failed, where the associated feeder is a critical link between the 132kV networks in the north and the south of Sydney. This circuit breaker had been included in the "C2" category of equipment at time of the regulatory submission. The "A" phase pole of the air-blast circuit breaker fractured, and subsequently collapsed, and caused the "B" phase pole to explode under high air pressure resulting in a large amount of porcelain being spread around the switchyard and damage to auxiliary equipment (see attached pictures).

This type of circuit breaker exists in two EnergyAustralia substations. In total, there are 31 circuit breakers, with some being installed in 1960 and some in 1968, which means they have almost reached their service life. The ACCC's decision was to exclude the costs of replacing these assets from EnergyAustralia's forecasts as the expenditure was not required prior to 2009.

Inspections of all these circuit breakers were undertaken to determine whether there was evidence to suggest a similar failure might occur in other circuit-breakers of this type. Inspections found cracks in the circuit breaker casting of varying degrees of severity, and each circuit breaker was placed in one of three categories:

1. significant cracks observed;
2. hairline cracks observed; and
3. no cracks observed.

Table 2 – Condition of circuit breakers

	Substation 1	Substation 2	Total
Category 1: Significant Cracks Observed	2	3	5
Category 2: Hairline Cracks Observed	7	2	9
Category 3: No Cracks Observed	10	7	17
Total number of CBs at site	19	12	31

EnergyAustralia immediately initiated an emergency replacement program of these circuit breakers. Costs associated with this replacement are outside the forecasts allowed by the regulator.

Figure 1 – Air-Blast Circuit Breaker

Figure 2 – Failed Circuit Breaker